The REopt Web Tool User Manual

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List of Acronyms

AC	alternating current
AMO	Advanced Manufacturing Office
AOP	annual operating plan
API	Application Programming Interface
AVERT	AVoided Emissions and geneRation Tool
CAPEX	capital expenditure
CBI	capital cost-based incentives
CHP	combined heat and power
CO2	carbon dioxide
CO2e	carbon dioxide equivalent
COP	coefficient of performance
CRB	Commercial Reference Building
DC	direct current
DER	distributed energy resource
DOE	Department of Energy
DOMHW	domestic hot water
EIA	Energy Information Administration
EPA	Environmental Protection Agency
ESPC	energy savings performance contract
GHP	geothermal heat pump
GHX	geothermal heat exchanger
HHV	higher heating value
IRR	internal rate of return
ISO	International Organization for Standardization
ITC	investment tax credit
JSON	JavaScript Object Notation
LID	light-induced degradation
MACRS	Modified Accelerated Cost Recovery System
NIST	National Institute of Standards and Technology
NREL	National Renewable Energy Laboratory
O&M	operations and maintenance
PBI	production-based incentive
PPA	power purchase agreement
PV	solar photovoltaics
RE	renewable energy
SAM	System Advisor Model
SOC	state of charge
T&D	transmission and distribution
TES	thermal energy storage
UESC	utility energy service contract
URDB	Utility Rate Database
WAHP	Water-to-air heat pump
WIND	Wind Integration National Dataset

Executive Summary

The REopt web tool evaluates the economic viability of grid-connected solar photovoltaics, wind, combined heat and power, geothermal heat pumps, and electric and thermal storage at commercial and small industrial sites. It allows building owners to identify the system sizes and dispatch strategies that minimize the site's life cycle cost of energy. The REopt web tool also estimates the amount of time on-site generation and storage can sustain the site's critical load during a grid outage and allows the user the choice of optimizing for energy resilience or clean energy goals. It is primarily used to inform project development decisions and to support research on the factors that drive project feasibility for market development and policy analysis. It is available through a web interface, application programing interface, and open-source code.

This user manual provides an overview of the model, including its capabilities and typical applications; inputs and outputs; economic calculations; technology descriptions; and model parameters, variables, and equations. The model is highly flexible and is continually evolving to meet the needs of each analysis. Therefore, this report is not an exhaustive description of all capabilities, but rather a summary of the core components of the model. Tutorials that guide users through the tool inputs and results are available here: https://reopt.nrel.gov/user-guides.html. A user forum discussion board with questions and answers concerning using the REopt optimization tool can be found here: REopt Web Tool User Forum.

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1 Introduction

The REopt® web tool evaluates the economic viability of grid-connected solar photovoltaics (PV), wind, combined heat and power (CHP), geothermal heat pumps (GHP), and storage at commercial and small industrial sites. It allows building owners to identify the system sizes and dispatch strategies that minimize the site's life cycle cost of energy. The REopt web tool also estimates the amount of time on-site generation and storage can sustain the site's critical load during a grid outage and allows the user the choice of optimizing for energy resilience.
The REopt web tool allows users to screen the technical and economic potential of distributed energy technologies on their own or in combination with each other. The user can select default performance parameters or enter user-specified performance parameters that are consistent with the model architecture and assumptions. By default, technology sizes will be determined by the model although the user can instead specify a size to be evaluated within a predetermined range.

Users are cautioned that although this model provides an estimate of the techno-economic feasibility of PV, wind, CHP, GHP, and storage installations, this is not a design tool. The results are indicative of a potential opportunity; they do not describe a design for procurement. Investment decisions should not be made based on these results alone.

This report primarily describes access of the REopt web tool through the web-interface, or user-interface, although some specific features only accessible via the application programming interface (API) are occasionally described. Tutorials that guide users through the tool inputs and results are available here: https://reopt.nrel.gov/user-guides.html.

1.1 Applications

Although a variety of potential applications are possible, the REopt web tool is primarily designed to address two use cases:

- **Project development decision support:** The REopt web tool is used to evaluate the technical and economic feasibility of PV, wind, CHP, GHP, and storage projects early in the project development process. In a typical development process, sites are qualified using an iterative analysis approach employing increasing levels of rigor and detail around key input assumptions with each successive iteration. This approach is designed to identify potential fatal flaws as quickly as possible and with a minimum of effort and expense. The REopt web tool can be used for early screenings that rely on minimal site information. The default assumptions for many parameters, such as modeled building loads and industry average cost data, are sufficient for this initial screening. Projects without obvious flaws are reanalyzed using increasing levels of actual site- and technology-specific information. In this case, many of the default assumptions may be overridden with specific values based on more detailed investigation and qualification of the site.
- **Research-related uses:** The REopt web tool is used to research the general conditions and factors driving project feasibility for market development and policy analysis. For example, the tool can be used to explore combinations of technology cost and incentive support needed for project feasibility on different building types and under different tariff structures.

1.1.1 What Questions Does The REopt Web Tool Answer?

The REopt web tool is used to evaluate the economics and resilience benefits of behind-the-meter distributed energy resources (DER) at specific sites. The REopt web tool answers questions such as:

- What type and size of DERs should I install to minimize my cost of energy?
- How much will it cost to achieve a sustainability goal?
- What is the most cost-effective way to survive a grid outage spanning one day? Three days? One week?
- How much would it cost to install a completely off-grid system?
- Where do market opportunities exist for DERs, now and in the future?
- How do I optimize system control across multiple value streams to maximize project value?

1.1.2 What Questions Does The REopt Web Tool NOT Answer?

The REopt web tool is not used to answer questions about:

- **Front-of-the-meter or utility projects.** The REopt web tool is designed to model the economics of DER at specific sites, behind the utility meter. It models opportunities to reduce utility bills through demand reduction and energy arbitrage. It does not capture front-of-the-meter value streams like demand response, frequency regulation, or ancillary services.
- **Regional or national energy adoption.** The REopt web tool is not used to predict adoption of energy technologies across city, regional, or national-scale systems.
- **Power flow.** The REopt web tool is an energy-balance model. It does not consider power flow characteristics.
- **Detailed design.** This is not a design tool. The results are indicative of a potential opportunity; they do not describe a design for procurement. The model generates the economic outlook for potential distributed energy technologies to identify whether they may be worth further consideration with more detailed assessment and consultation with professional engineers.
- **Building energy modeling.** Loads to be served by DER are inputs to the REopt web tool; it does not include building energy modeling.

While the REopt web tool is not designed to answer the questions above, researchers are continually adapting the Application Programming Interface (API) and open source code as well as integrating the REopt web tool with other models to address emerging research questions.

1.1.3 Who Uses The REopt Web Tool?

The REopt web tool is accessible to users with a range of skill levels and data. Inputs are configured so that increasingly detailed input options are progressively exposed to users. Basic users, or those with minimal data, will enter minimal site-specific information to run an analysis. Results will provide an initial, high-level assessment of project feasibility at a site. Advanced analyses will use detailed site information (e.g., exact tariffs, actual load profiles, actual site area and roof space available) to produce results with a higher degree of accuracy.

The REopt web tool is used by:

- **Building owners, energy managers, and energy consultants** to understand the economics and resilience benefits of DER at their site
- **Developers** to understand the economics of DER across a range of potential sites
- **Utilities** to understand the economics of DER at their customers' sites
- **Industry** to understand optimal control strategies for DER
- **Researchers** to understand economics and resilience benefits of integrated suites of DER.

1.1.4 How Does The REopt Web Tool Compare with Other Models?

Other models that also evaluate the technical and economic viability of distributed energy at the site level include RETScreen, System Advisor Model, HOMER, DER-CAM, EnergyPro, TRNSYS, iHOGA, eSyst and ficus. The unique features of the REopt web tool include:

- **Optimization:** The REopt web tool optimizes system size and dispatch strategy (the user does not have to enter the size/dispatch)
- **Integration:** The REopt web tool assesses an integrated suite of electric and thermal technologies (rather than each technology individually)
- **Accessibility:** The REopt web tool is accessible to novice users with just three required inputs while also offering over 100 optional inputs and an API and open-source code for advanced users
- **Transparency and Extendibility:** The REopt web tool provides transparency into the model formulation and extendibility of the code through the open-source model.

1.2 Accessing The REopt Web Tool

The REopt web tool is available in three formats:

- Web interface: reopt.nrel.gov/tool. The web interface allows users to easily input data, run analysis, and view results for a single site in a graphical user interface.
- API: https://developer.nrel.gov/docs/energy-optimization/reopt-v1/. The API allows users and software developers to programmatically interface with the REopt tool. The API can be used to evaluate multiple sites and perform sensitivity analyses in an efficient manner, and to integrate REopt tool capabilities into other tools. The REopt API is available on the NREL developer network. Nonprofit or commercial use of these web services is free, subject to hourly and daily limits on the number of web service requests as described at developer.nrel.gov/docs/rate-limits.
- Open source: https://github.com/NREL/REopt_API. The open-source code allows software developers to modify the REopt tool code or host it on their own servers. It is licensed under BSD-3, a permissive license that allows for modification and distribution for private and commercial use.

The REopt web tool is a free, publicly available web version of the more comprehensive REopt model, which is described in Cutler et al. (2017). The full REopt model is not available outside NREL. The full model includes technologies that are not yet available in the REopt web tool such as solar hot water and solar ventilation preheating. NREL is gradually transitioning capabilities from the internal version to the public REopt web tool version as time and funding allow. Early versions of the REopt web tool were called REopt Lite. Those versions contained a smaller subset of the full REopt model's capabilities.

1.3 Citing The REopt Web Tool

To cite REopt web tool analysis results for a specific site, please use:

> NREL. [Year]. "REopt Results from [Site Location], [Technologies] [Financial or Resilience] Evaluation." REopt Web Tool. Accessed [Month Day, Year]. [URL].

For example:

> NREL. 2020. "REopt Results from Palmdale, CA, PV and Battery Storage Financial Evaluation." REopt Web Tool. Accessed May 4, 2020. https://reopt.nrel.gov/tool/results/d875d523-6969-405b-9258-b428169ca42f.

To cite the REopt web tool model in general, please use:

> S. Mishra, J. Pohl, N. Laws, D. Cutler, T. Kwasnik, W. Becker, A. Zolan, K. Anderson, D. Olis, E. Elgqvist, Computational framework for behind-the-meter DER techno-economic modeling and optimization—REopt Lite, *Energy Systems* (2021).

1.4 Feedback

Contact NREL at REopt@nrel.gov to offer suggestions or feedback on the REopt web tool or to explore options for more detailed modeling and project development assistance.

2 General Description

The REopt web tool is a techno-economic decision support model used to identify potentially cost-effective investment opportunities for buildings, campuses, communities, and microgrids. Formulated as a mixed-integer linear program, the REopt web tool solves a deterministic optimization problem to determine the optimal selection, sizing, and dispatch strategy of technologies chosen from a candidate pool such that loads are met at every time step at the minimum life cycle cost. The candidate pool of technologies typically includes PV, wind power, CHP, GHP, electric and thermal energy storage (TES), absorption chillers, and the existing heating plant, cooling plant, and service connection from the electric utility.

The REopt web tool identifies technologies and operational strategies of these technologies that might reduce the cost of energy services at a particular site. Energy services include the site's electricity and thermal energy requirements. These services are conventionally supplied by an electric utility (the grid), a natural gas utility, and off-site fuels transported to the site by pipeline, truck, or rail.

To identify the least-cost set of resources that can provide a site's energy services, the model weighs the avoided utility costs (grid-purchased electricity and purchased fuels) against the cost to procure, operate, and maintain additional on-site DER. If the avoided costs are greater than the ownership costs, the system is life cycle cost effective. The REopt web tool identifies which technologies are life cycle cost effective, then sizes each technology[1] and determines their dispatch to maximize their economic value for the set of inputs that describe the case under consideration.

The loads, utility costs, and renewable resources are modeled for every hour of one year. We assume the modeled year represents a typical year and that the load and resources will not change significantly over the user's selected analysis period. Scenarios with load growth or declines over many years cannot be modeled. The REopt web tool is a time series model in which energy balances are ensured at each time step and operational constraints are upheld while minimizing the cost of energy services for a given customer. A primary modeling assumption is that decisions made by the model will not impact markets, i.e., the model is always assumed to be a price-taker. This is in contrast to price maker models in which pricing is a decision variable. The REopt web tool also does not model power flow or transient effects.

The REopt web tool solves a single-year optimization to determine N-year cash flows, assuming constant production and consumption over all N years of the desired analysis period. The REopt web tool assumes perfect prediction of all future events, including weather and load. All costs and benefits are discounted with the user-specified discount rate to present value using standard economic functions. The user can enter constant rates of change for future costs of grid power, fuels, and operations and maintenance (O&M) for inclusion into the discounting factors to account for projected cost escalation (or de-escalation) rates. Incentives and taxes are also included in the life cycle cost analysis if the user chooses to include them.

Because the objective function is set to minimize life cycle costs of energy services, sometimes the solution includes no new technologies because the net present value (NPV) would otherwise be negative. In this case, the baseline system is the cost-optimal result. By adjusting some inputs, the user can specify a system type and size rather than having the REopt web tool solve for this. In this case, systems are 'forced' into the solution whether it is cost effective or not. In some cases, the model may find that even though the addition of the new asset was forced in by the user, the model may not utilize it because the cost of operating the new asset would be greater than avoiding its use. For example, in a scenario where electricity costs are low, a CHP system, even if it had no initial capital costs, could be more costly to operate due to the cost of the fuel and maintenance than it is to purchase grid electricity and continue to provide heat through the existing heating plant.

2.1 Technology Models

The REopt web tool models the following technologies: PV, wind power, CHP, GHP, battery energy storage, TES, absorption chillers, and backup diesel generators. Because the model weighs the cost-benefit tradeoff of these technologies, we also include models of the serving electrical utility rate tariff, as well as a facility's existing heating and cooling systems as required.

All technologies are dispatched on an hourly basis for a typical, or representative, year. There is an implicit assumption that typical meteorological power production profiles for PV and wind

[1] The one exception is that REopt does not size GHP for economic optimization. If selected as a technology, the GHP system is assumed to serve all of the space heating and space cooling.

are valid over the analysis period, e.g., long-term climate change projections are not included. Furthermore, the user's entered representative loads are assumed not to change significantly over the analysis period.

Figure 1 illustrates the general system configuration of the REopt model, including generation sources, storage devices, and loads. Within the electric load and the heating load, dashed boxes show a subset of those loads that could be dispatched by REopt if certain technologies are selected by the user for consideration.

The assumed existing infrastructure, namely the electrical grid connection, boiler/heating system, and cooling system are shown in bold. The electrical, heating, and cooling distribution systems are also existing infrastructure that the model does not size or cost. The optional user-selected components that the model can consider for parallel operation with the existing sources are not bolded.

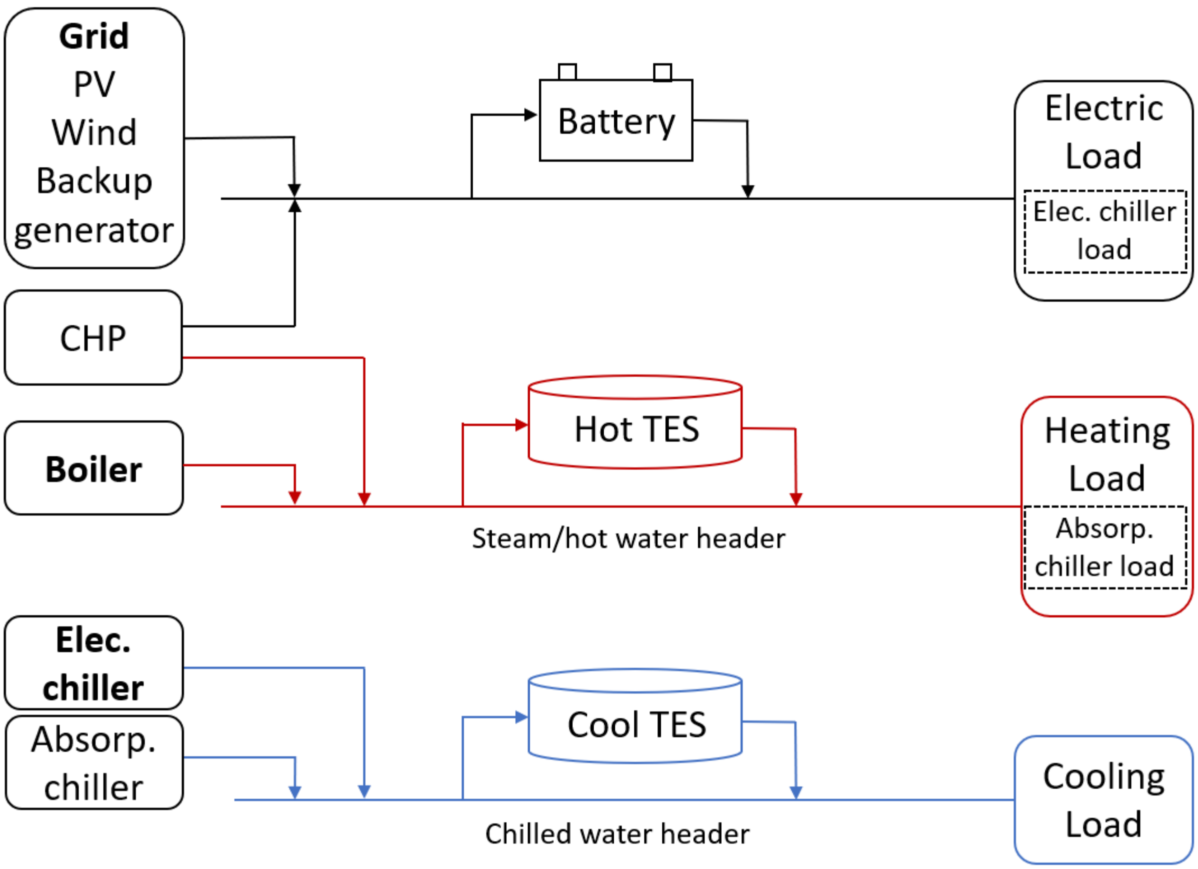

Figure 1. System diagram for REopt power, heating, and cooling technologies and loads

The user can select to screen for all or some subset of the available technologies. If the user does not choose to consider chilled water TES or absorption chiller as an additional potential use of the CHP waste heat or GHP, then the cooling load is not a required input and an electrically driven cooling system is not explicitly modeled. In this case, the cooling load is assumed to be embedded within the total electrical load and is met by serving all the site's electrical load.

The REopt web tool automatically queries NREL databases and modeling tools, including the Utility Rate Database to gather utility rate tariffs, and PVWatts®, System Advisor Model, and Wind Toolkit to gather renewable energy resource data. PV and wind generation estimates are location-specific time-series profiles. CHP produces both electric and thermal energy. Part-load electric efficiency and heat recovery performance can be modeled as an option. An absorption chiller that produces chilled water from a supply of hot thermal energy may also be considered in conjunction with CHP. GHP can be modeled as a retrofit to replace existing heating and cooling systems to see the impacts on lifecycle costs and potential interaction with other technologies screened. The backup diesel generator is available as a power source during grid outages. Utility supply is modeled as an infinite source of energy for the site, which can be turned off by the user to explore impact of loss of grid power on DER results and economics.

The electric load is met by the grid, any electricity-producing DER, or discharge from the battery. The modeled facility's heating system conventionally serves the heating load, and the electric cooling system conventionally supplies the cooling load. With GHP, these loads are assumed to be met entirely by the GHP system. With CHP, absorption chiller, chilled water TES, and hot water TES, the following flows of energy are also considered:

- The grid and optional PV, wind power, and CHP can provide electricity to the electric load, and electricity from these resources can be stored in the battery if a battery is included in the solution.
- The battery, subject to state of charge (SOC), can supply electricity to the electrical load.
- The boiler and CHP can supply hot thermal energy to the heating load, including an optional absorption chiller, and, for hot water systems, hot water can be stored in the hot water TES if hot water TES is included in the solution.
- Hot water TES, subject to level of stored energy, can supply hot water to the heating load, including an absorption chiller if it is included in the solution.
- The electric chiller and the optional absorption chiller can supply chilled water to the cooling load, and chilled water can be stored in the chilled water TES if chilled water TES is included in the solution.
- The chilled water TES, subject to level of stored energy, can supply chilled water to the cooling load.
- The backup diesel generator can serve electrical loads in resiliency analyses when the user selects to include grid outages.

Equipment redundancy requirements and factors of safety are not modeled.

2.2 Formulation

The REopt web tool solves a mixed-integer linear program. The objective function minimizes total life cycle cost, which consists of a set of possible revenues and expenses over the analysis period, subject to a variety of integer and non-integer constraints to ensure that thermal and electrical loads are met at every time step by some combination of chosen technologies.

The constraints governing how The REopt web tool builds and dispatches technologies fall into the following categories:

- Load constraints: Loads must be fully met by some combination of renewable and conventional generation during every time step. Typically, hourly or 15-minute time steps are used in the model.
- Resource constraints: The amount of energy that a technology can produce is limited by the amount of resource available within a region or by the size of fuel storage systems. The energy production of variable technologies is limited by the renewable resource at the location, while the utility grid is assumed to be able to provide unlimited amounts of energy.
- Operating constraints: Dispatchable technologies may have minimum turndown limits that prevent them from operating at partial loads below a specified level. Other operating constraints may limit the number of times a dispatchable technology can cycle on and off each day or impose minimum or maximum SOC requirements on battery technology.
- Sizing constraints: Most sites have limited land and roof area available for renewable energy installations, which may restrict the sizes of technologies like PV or wind. The client may also specify acceptable minimum and maximum technology sizes as model inputs.
- Policy constraints: Utilities often impose limits on the cumulative amount of renewable generation a site can install and still qualify for a net metering agreement. Other policy constraints may restrict the size of a variable technology system in order for it to be eligible for a production incentive.
- Scenario constraints (optional): Constraints may require a site to achieve some measure of energy resiliency by meeting the critical load for a defined period of time with on-site generation assets.

For more details including the complete mathematical formulation, refer to Appendix B.

2.3 Temporal Resolution

The REopt web tool uses time series integration to combine the energy production from concurrently operating technologies. The optimization model assumes that production and consumption are constant across all years of analysis, and so only considers the energy balance of Year 1. The typical time step is one hour, resulting in 8,760 time steps in a typical N-year analysis. This ensures that seasonal variation in load and resource availability is captured. Time steps can be adjusted in the API; in the web tool, they are set to hourly.

3 Getting Started

3.1 Logging In

Upon accessing the REopt web tool (https://reopt.nrel.gov/tool), the user has the option of creating or logging into an existing user account via the Log in/Register link in the upper right corner. The REopt web tool can be used without registering or logging in to a user account. However, if a user chooses to set up an account and to log in before running evaluations, their evaluations are saved and can be accessed later.

In order to create a detailed custom electricity rate, build a custom critical load profile, or manage typical and critical load profiles, users must be registered and logged into their account.

There are options to create accounts using Google and/or Facebook. Users can create a Google account that is associated with a non-gmail.com address by clicking on “Use my current email address instead," entering an email address, then following the instructions to verify the ownership of the email address entered. Users signing in with Facebook must be signed into their Facebook account and have platform apps enabled in that account.

3.1.1 User Dashboard

Once logged in, the Saved Evaluations button takes the registered user to a dashboard which presents a summary of their stored data from previous evaluations, along with links to view or download the results page of each evaluation in their browser, copy the evaluation as a basis for creating an edited new evaluation, or to delete the saved evaluation. An additional option exists for users who access the REopt tool through the API. A JSON (JavaScript Object Notation) formatted file containing the evaluation inputs can be downloaded to be used with the API.

3.1.2 Custom Load Profiles

The Load Profiles button gives the registered user the option of viewing Saved Typical Loads or Saved Critical Loads. The Typical Load Profiles page presents a button to upload a new load profile and a summary of all previously uploaded typical load profiles, along with lists of the evaluations that used each load profile, a graph of the load profile, and the option to download the profile. Typical load profiles can be deleted if they are not associated with any evaluations. The user must first delete all associated evaluations in order to enable deletion of a typical load profile.

The Critical Load Profiles page presents a button to upload a new critical load profile and another button to build a new critical load profile. The page also provides a summary of all previously uploaded or built custom critical load profiles, along with lists of the evaluations that used each critical load profile, a graph of the load profile, and the option to download the profile. Critical load profiles can be deleted if they are not associated with any evaluations. The user must first delete all associated evaluations in order to enable deletion of a typical load profile.

3.1.3 Custom Rates

The Custom Rates button takes a registered user to a list of previously defined custom electricity rates, or allows them to define a new electricity rate.

3.2 New Evaluation

3.2.1 Step 0: Gathering Data

The Step 0 section details the advantages of optional registration and logging in to a private account, including the ability to save evaluations, create custom electricity rates, build custom critical load profiles, and manage saved typical and critical load profiles. It also lists the data that should be gathered for different types of evaluation. A Financial evaluation will require site location, electricity rate, and either a custom load profile or the combination of a building type and an annual energy consumption estimate for that building. A Resilience evaluation will require these data plus data defining a planned or potential electric outage. The extra resilience data includes a way of determining the load that will need to be met in an outage: either a percentage critical load factor, a custom critical load profile, or the critical load components that would be required in an outage that can be used to build a critical load profile. The other key data are the expected or desired outage duration to be survived and a starting date and time for the outage. If a generic potential outage is to be modeled, then a worst-case scenario can be used by selecting the outage start time as the peak time of the critical load profile.

3.2.2 Step 1: Choose Your Focus

The first step in creating a new evaluation is selecting the focus of the analysis—whether to optimize for financial savings or energy resilience. The default selection is financial savings. If Financial is selected, then Resilience inputs are hidden.

Financial mode optimizes system sizes and dispatch strategy to minimize life cycle cost of energy. Resilience mode does the same thing, but with the added constraint that on-site resources must sustain the critical load, without the utility grid, during the designated outage period. Due to the explicit modeling of the utility grid within the REopt web tool, the model can be used to simulate grid outages by turning off the grid for certain time steps. The load profile can also be modified during these grid outages to represent a "critical" load (either via a percent scaling factor or by splicing in a critical load). This enables evaluation of all technologies in the model, both during grid-connected mode (vast majority of the year) and during grid outages. This capability is especially important for renewable energy technologies because they are able to generate value during grid-connected mode while also supporting a critical load during a grid outage (whereas backup generators may only be able to operate during an outage due to air quality permits).

3.2.3 Step 2: Select Technologies

The second step is selecting the technologies to be included in the analysis—whether to evaluate PV, wind, battery storage, CHP, chilled water storage, or any combination of these technologies. If CHP is selected, you may also select to evaluate hot water storage and/or absorption chiller. If a Resilience evaluation has been chosen, a diesel generator evaluation is also given as an option. Only the inputs for a selected technology are visible. Inputs for any technology that is not selected are hidden.

3.2.4 Step 3: Enter Data

The third step is entering site-specific data for the scenario that the user wishes to evaluate. This data includes the location, electricity rate, and consumption details, as well as financial constraints. A variety of inputs are necessary for a REopt web tool analysis, but the tool provides editable default values for most of these parameters. Note that there is an option in the right margin of each section to “Reset to default values.” See Section 20 for information on default values.

For a Financial evaluation, there are three or four required inputs that the user must enter. Two of these entry fields are displayed in the Site and Utility Inputs section when the tool is first opened. These two inputs are site location and the applicable electricity rate for that site location. If CHP technology is selected, fuel cost is also required in this section. The final required input is the typical load—entered either as a simulated building type plus an annual energy consumption or as a custom load profile data file upload—entered in the Load Profile section. If CHP technology is selected, a thermal load profile, or profiles, are also required in this section.

For a Resilience evaluation, there are four additional required inputs. The first is the critical energy load profile—entered either as a critical load factor percentage, as a custom critical load profile data file upload, or as a custom-built critical load—in the Load Profile section. The final three required inputs are the outage duration, outage start date and outage start time for the grid outage that the resilience evaluation will model.

There is a total of twelve possible data input sections: Site and Utility, Load Profile, Resilience (visible only when the resilience evaluation is chosen), Financial, Renewable Energy and Emissions, PV, Battery, Wind, Generator (also visible only when the resilience optimization is chosen), Combined Heat & Power, Geothermal Heat Pumps, and Chilled Water Storage. Inputs for Hot Water Storage and Absorption Chilling are found under Combined Heat & Power. As each section is expanded, the key driver input parameters for that Data Input section are displayed. In most cases these top inputs in each section will have the greatest impact on the results of the evaluation. Additional parameters in each section can be displayed by selecting the "Advanced Inputs" option.

Parameters with default values have these prepopulated values displayed in light gray text in the data entry boxes. All these values can be overridden, and those that have been altered by the user will display in a darker text and the default will be displayed in the right margin next to the input box. Each separate section, as well as the entire form, has an option to reset the parameters to default values. See Section 20 for details and explanations of these values.

When all desired inputs have been entered and/or edited, the final step is to select the Get Results button. A new page will display while the tool is optimizing the results. This may take up to several minutes to complete, depending on the complexity of the analysis. The Results page displays recommended system sizes, potential savings, the system dispatch strategy returned from the API, and, if requested, analysis of resilience system economics. The user will have the option of downloading a dispatch spreadsheet, a pro forma spreadsheet, and running an outage simulation. The user can also return to the input page to edit the inputs and alter the scenario for a new evaluation.

Users are cautioned that, although this model provides an estimate of the techno-economic feasibility of solar, wind, CHP, GHP, and storage installations, this is not a design tool. The results are indicative of a potential opportunity; they do not describe a design for procurement. Investment decisions should not be made based on these results alone. Before moving ahead with project development, verify the accuracy of important inputs and consider additional factors that are not captured in this model.

3.3 International Use

Although the REopt web tool is designed for use with locations within the United States, there is a link in the upper right corner, to the left of the Log In/Register link, that provides suggestions for adjustments that can allow the use of most of the tool's features for international locations.

3.3.1 Site Location & Utility Rate

Selecting a site location outside the United States will prompt a message that no electricity rates can be found for the location. This is because the utility rate database used by the REopt web tool does not include international locations. However, custom utility rates can be entered as simple annual or monthly rates. Detailed rates, with variable prices dependent on times and months, can also be entered if the user is registered and logged in to a user account. Details of rate structures for some international locations can be found at the International Utility Rate Database.

3.3.2 Currency

Currency values are all in U.S. dollars. Conversions from the local currency to U.S. dollars can be made for inputs of utility rates, system costs, and incentive values. Conversion of the final results of the evaluation will then be necessary, from U.S. dollars back to the local currency. One popular tool for currency conversion approximation is the Currency.Wiki.

3.3.3 Load Profile

The Load Profile option for simulated load data is based on U.S. building and climate area data. If this simulated load option is used, the simulated load profile should be checked for reasonableness for the climate of the selected location.

3.3.4 Financial Information

Financial, tax and incentive input defaults in all sections need to be carefully considered and altered to match local tax and interest rates and available financial incentives. Default costs for technology systems are also based on typical costs in the United States. Resources for researching international renewable energy costs can be found at the International Renewable Energy Agency.

3.3.5 Solar Production Data

Solar production data is taken from the PVWatts dataset, which includes many international locations. The REopt web tool will use the closest available location that is found to have resource data, so the user should independently confirm that PVWatts includes data for a location that is acceptably close to their site location. The available resource data locations can be found using NREL's PV Watts. Users who have access to hourly custom solar production data for their site can upload it in the Advanced Inputs section, and it will be used instead of PVWatts data.

3.3.6 Wind Resource Data

Wind systems cannot currently be modeled from the web tool user interface for international locations due to lack of international wind resource data. However, if the user has hourly wind resource data for their site, they can use this data in the API, instead of the web tool interface, to complete an optimization.

3.3.7 Ground Thermal Conductivity Data for GHP

For GHP, a number of ground properties are assumed and these assumptions are dependent on location in the United States based on climate zone. For international sites, the default ground thermal conductivity is based on the same data set. A geometric calculation to find the nearest US city that represents ground thermal conductivity associated with the climate zone will be done.

Note: Ground thermal conductivity is a key parameter that drives the size of the ground heat exchanger, and therefore the total cost of GHP. Users are advised to do research on this parameter and run appropriate sensitivities during the screening phase and to do ground properties tests before investing in GHP.

3.3.8 Ambient Temperature

For GHP, the geothermal heat exchanger model requires typical hourly ambient temperature data. This temperature data is pulled in from the PVWatts API. The PVWatts API is described in Section 10 Photovoltaics.

4 Economic Model

As previously mentioned, the objective of the optimization is to minimize life cycle costs, i.e., to maximize NPV. Other financial metrics like internal rate of return (IRR) and payback are reported but cannot be selected as the driving objective. It is not unusual to get a ‘null’ solution, where no technologies are recommended, if DERs are not found to be cost-effective. The user can select from two financial models: self-financed owner-operator and third-party financed.

The approach and terminology are based on the *Manual for the Economic Evaluation of Energy Efficiency and Renewable Energy Technologies* (Short, Packey, and Holt 1995) and abides by the life cycle cost methods and criteria for federal energy projects as described in the Federal Code of Regulations 10 CFR Part 436 - Subpart A, and which are detailed in National Institute of Standards and Technology (NIST) Handbook 135, Life-Cycle Costing Manual for the Federal Energy Management Program (Fuller and Petersen 1995).

4.1 Definitions, Inputs, and Assumptions

The primary economic calculations considered are the NPV of the alternative energy project and the total LCC. LCC[2] is the present value of all costs, after taxes and incentives, associated with each project option. NPV[3] is the present value of the savings (or costs if negative) realized by the project. The general equation for NPV is given below:

$$\textit{NPV of alternative} = \textit{LCC of Business-as-Usual Case} - \textit{LCC of Investment Case} \qquad \text{Equation 1}$$

Here, Business-as-Usual Case refers to the total cost of energy services over the analysis period if the site continues to purchase energy services solely from its existing suppliers. These are typically the site’s existing serving utility, but if on-site energy systems exist, those are also included in the Business-as-Usual Case. For example, PV systems or CHP plants already in service at the site are modeled to ensure the Base Case scenario properly represents the site’s current utility demand, supply sources, and costs. Life cycle utility costs include annual cost escalation rate projections specific to and specified by the client.

The Investment Case is the project scenario with additional alternatives to continuing the business-as-usual operation. The Investment Case considers:

[2] LCC or total life-cycle cost has the meaning as described in (Short, Packey, & Holt, 1995), where it is abbreviated as TLCC

[3] NPV as described here has the same meaning as Net Savings (NS) as described in (Fuller & Petersen, 1995)

- Capital Expenditure (CAPEX[4]) of the alternative project
- O&M costs of the alternative project
- The cost of fuels
- All applicable incentives made available by utilities, states or the federal government (e.g., Investment Tax Credit (ITC), Production Tax Credit, and accelerated depreciation)
- Balance of remaining utility costs if the alternative project considered does not supply all of the site's energy loads.

Costs that occur in years beyond the base year (Year 0) are discounted to present value. An end-of-year discounting convention is applied. The discounting function properly discounts for:

1. One-time future costs (e.g., a PV system's inverter replacement in Year 15 if it is included in the O&M forecast)
2. Annual recurring costs (e.g., regular annual maintenance for a wind turbine in a real economic analysis)
3. Annual recurring costs that are escalating at a fixed rate each year (e.g., an annual utility cost escalation rate is applied to the base year utility costs to account for projected utility rate increases).

With these considerations in mind, the primary economic inputs into the REopt web tool are as follows:

- Discount rate: The rate at which the future value of all future costs and savings is discounted—an after-tax value if the owner is a taxable entity
- Current utility costs and assumed utility cost escalation rates: The expected annual escalation rate for the price of electricity or fuel
- Length of the analysis period: The financial life of the project
- Income tax rate: The percent of income that goes to tax. The tax value default is currently 26%—the sum of a 21% federal rate plus a 5% average state rate
- O&M cost escalation rate: The expected annual escalation rate for O&M costs over the financial life of the system
- Tax and non-tax-based incentives depending on the client's tax disposition.

To calculate the economic outputs, the REopt web tool makes the following assumptions:

- CAPEX are considered overnight costs (i.e., all projects are completed at the end of Year 0 and produce energy starting in Year 1) and assumed to be the same in both ownership models (see Section 4.2). Construction periods and construction loans are not modeled.
- A site's annual electric and thermal load demand profiles remain constant from year to year for the duration of the analysis period.
- One-year discounting periods are used (i.e., no mid-year discounting subperiods).
- All cash flows occur at end of year.
- When tax benefits are considered, the system buyer has sufficient tax appetite to capture all available tax incentives in their entirety.

[4] Note that the term CAPEX and capital costs are both used interchangeably in this document and have the same meaning.

- O&M costs escalate at the O&M cost escalation rate.
- Sales tax, insurance costs, and property taxes are not considered.
- Debt service coverage and reserve requirements are not considered.

Although the input fields in the user interface are labelled as nominal values, a real or nominal analysis can be performed as long as discount rates, O&M cost escalation rate (general inflation), and utility cost escalation rates are consistently represented in real or nominal terms. The REopt web tool assumes all technologies except battery storage have a useful life equal to the analysis period; any residual value at the end of the analysis period is not captured. For battery storage, one replacement can be modelled during the analysis period.

4.2 Ownership Models

Many economic or pro forma financial analyses consider project options only from the perspective of the project owner, assuming that the party that consumes the energy from an energy-producing technology also purchases, owns, and operates the system. However, on-site renewable energy and nonrenewable energy systems are often financed and owned by an unrelated party that does not consume the energy output but instead sells these energy services to the owner of the building or site. In this type of business arrangement, the site acts as the "host" (or off-taker) of the energy project while the third party both finances and owns the project.

A facility owner may consider a project of this type if they do not have or do not want to use their own funds to build energy systems, or if they do not want to take on ownership overhead. In this case, facility owners want to know if a project is economically feasible if a third party builds and operates the system at the facility and sells the energy services to the facility owner. Business arrangements of this type are sometimes referred to as alternative financed projects and include power purchase agreements (PPAs), energy savings performance contracts (ESPCs) or utility energy service contracts (UESCs).

The REopt web tool is formulated to allow techno-economic screenings of projects for facilities under the following general ownership models:

1. Single Party Economic Model: The facility is interested in projects that the facility owner will purchase, own, operate, and consume energy from. This is the conventional ownership model described in the references. The economic screening here answers the question: Should the facility owner consider buying additional energy systems to displace energy purchases from their existing utility and/or other existing assets?
2. Third-Party Economic Model: The facility owner is interested in procuring energy services from a third party that owns and operates the system(s) on or adjacent to the facility owner's property, and sells the energy produced to the facility owner. Here, there are two parties, the Third-Party Owner and the Host, each with potentially different discount rates and income tax rates. The facility owner is the system Host, or consumer of the energy from the project. The Third-Party Owner builds and operates the systems and sells energy services to the Host. The Third-Party Owner is an unrelated party who invests in the project as a business venture. The economic screening here answers the question: Should the facility owner consider engaging an energy services provider to procure electricity, heat, or other energy services to reduce total costs of energy paid to

their conventional utility providers or to consume electricity or heat provided by other existing assets?

The Third-Party model of ownership uses the same general economic principles as the Single Party model, but considers two sets of discount rates and tax rates: (1) the Third-Party Owner's discount rate and tax rate for evaluating ownership costs and revenues necessary for the project to be a sound investment for the Third-Party Owner, and (2) the Host's discount rate and tax rate to determine the economic merits of procuring energy services from the Third-Party Owner instead of the serving utility. Alternative financing projects are complex and ultimately need to be evaluated using complex proformas that depend on the financing approach taken. The Third-Party Model in the REopt web tool is a simplified screening-level analysis to identify potential opportunities for facilities considering alternative financing.

The Third-Party Model screens projects that the facility would engage in under an alternative financing plan (e.g., through a PPA or an ESPC). The model considers the perspective of both the Third-Party Owner and the Host. The general approach is as follows:

1. Find the total Net Present Cost of the project using the Third-Party Owner's discount rate, tax rate and all incentives available to the project owner. This discount rate is the same as the Third-Party Owner's IRR. As applied in the REopt web tool, the Third-Party Owner's discount rate is Third-Party Owner's IRR after taxes.
2. Determine the annual payment (annuity) for energy services required by the Third-Party Owner over the analysis period to cover all ownership costs at the Third-Party Owner's discount rate (after tax IRR). In the user interface, this is both the Third-Party Owner's 'Annual Payment from Host' and the Host's 'Annual Payment to Third Party Owner'.
3. Determine the LCC of energy for the Host using the Host's discount rate, considering:
   - Purchasing energy from the serving utilities and fuel suppliers
   - Energy services payments the Host will make to the Third-Party Owner for procuring energy from the project.
4. Calculate the NPV for the Host, considering payments to conventional utilities in the Business-as-Usual Case and the sum of conventional utility costs and energy services payments in the Alternative Energy Case. If the NPV is greater than zero, the project is considered economically viable for the Host and the Third-Party Owner is able to meet their profit requirements.

4.3 Economic Incentives

The REopt web tool models three types of incentives for applicable technologies: capital cost-based incentives, production-based incentives, and tax depreciation.

4.3.1 Capital Cost Based Incentives

Capital cost-based incentives, or CBI, are structured either as a fraction of the total installed cost or as a rebate amount per DER unit capacity. The user can enter programmatic maximum rebate limits to CBI incentives. The value defaults to 'Unlimited.' Federal and state tax credits are entered as CBI in the REopt web tool. The federal percentage-based incentive is treated as a tax-based incentive to model the federal investment tax credit. All other incentives are not tax-based.

Incentives are considered in the following order: utility, state, then federal. For example, if there is a 20% utility incentive and a 30% state incentive, the 20% utility incentive would be applied first, then the 30% state incentive would be applied to the reduced cost. The incentives are not additive; that is, the site would not get a 20% + 30% = 50% discount.

4.3.2 Production Based Incentives

Production-based incentives, or PBI, are entered as a dollar value of the incentive per kWh produced. The number of years the PBI is available and the maximum incentive amount are available fields. Additionally, the user can enter a maximum available generator size for incentive programs that include a system capacity limit. If there is more than one production-based incentive offered (for example, a federal and a utility incentive), the combined value can be entered and should be discounted back to year one if the incentive duration differs.

4.4 Tax Policies

The Modified Accelerated Cost Recovery System (MACRS) is the current tax depreciation system in the United States. Under this system, the capitalized cost (basis) of tangible property is recovered over a specified life by annual deductions for depreciation. If available, the user may specify the duration over which accelerated depreciation will occur (five or seven years). When claiming the ITC, the MACRS depreciation basis is reduced by half of the value of the ITC.

5 Existing Facility Infrastructure

This section provides a detailed description and assumptions used for the performance models of the assumed existing facility infrastructure in the REopt web tool. This infrastructure includes electric utility service, space and domestic hot water heating systems, and a space cooling system. The REopt web tool does not size and cost this assumed existing infrastructure.

5.1 Utility Services

The site is assumed to be served by an electric utility and, if natural gas is selected by the user, a natural gas utility. In addition, if other fuel types are selected for the heating system or to be considered for use by the potential CHP system, we assume those fuel storage and delivery components are in place, i.e., they are not included in the REopt web tool cost models. The costs for fuels and power via the utility services are user inputs.

5.2 Heating System

If the user screens for systems to replace or augment facility heating, the model construct assumes the facility has an existing heating system. For CHP screening, the heating systems are assumed to be centrally located and that they could accommodate the integration of supplementary waste heat from a CHP unit. For GHP screening, the heating system can be either centralized or decentralized. The heating systems are modeled as a lumped heat generator; individual boilers in a multiple boiler facility or distributed heating systems are not individually modeled. Additionally, when screening for CHP, the user selects whether the heating system is hot water or steam in the user interface using the 'Existing boiler type' dropdown menu. A configuration with both steam and hot water cannot be modeled.

The model does not include heating system turn-down limits (minimum unloading ratio constraint) or minimum runtime constraints, e.g., the model allows the heating system to be off in one hour, run one hour, and then be off the following hour.

Natural gas is the default fuel for the heating system. Additional fuel options include propane, diesel, and biogas. For natural gas and biogas, the user enters costs in units of $/MMBtu while the costs for diesel and propane are entered in units of $/gallon. For the analysis, entered unit costs are converted from $/gallon to $/MMBtu using the following higher heating values (HHV)[5]:

- Diesel, 138,490 Btu/gallon (HHV)
- Propane, 91,420 Btu/gallon (HHV).

The user-selected fuel type impacts carbon dioxide (CO2) emissions accounting. See Section 9, Renewable Energy and Emissions.

Heating system efficiency is modeled as constant throughout the year, i.e., there are no efficiency adjustments for heating system loading. When screening for CHP, the default plant efficiency is dependent on whether the user selects hot water or steam for the process heat loop. Efficiency is based on the HHV of the fuel. The default heating plant efficiencies (HHV-basis) are 0.80 for a hot water plant and 0.75 for a steam plant. For GHP screenings, the heating system efficiency default is 0.80.

For hot water systems, the assumed loop temperatures are:

- Hot water supply temperature of 180°F
- Hot water return temperature of 160°F.

In a future release, the user will be able to adjust loop temperatures to inform adjustments to the CHP thermal efficiency (higher thermal efficiency if the required supply water temperature is lower, and vice versa).

For steam systems, the assumed loop pressure is 150 psig with return to the boiler at a temperature of 180°F. In a future release, the user will be able to adjust the steam pressure. Fraction of condensate returned is not a required input as described in Section 7.4, Heating Loads. If hot water TES is considered for hot water systems, the distribution loop temperature differential is used to estimate the tank's thermal storage capacity.

It is assumed that the existing heating system is sized to serve the maximum demand in the facility heating load with an additional 25% excess capacity. This value is a default assumption that can be changed by the user. This assumption imposes a maximum charging rate of hot water into hot water TES. See Section 16.2, Hot Water Thermal Energy Storage for details.

5.3 Cooling System

If the user chooses to consider chilled water TES or an absorption chiller, the facility cooling load is assumed to be served by a centralized cooling plant comprised of electrically driven

[5] https://afdc.energy.gov/fuels/fuel_comparison_chart.pdf

chiller(s). It is also assumed that the cooling plant could accommodate the integration of chilled water TES or a supplemental absorption chiller.

For GHP screening, the facility baseline cooling system can either be central plant or cooling units distributed throughout the facility.

The efficiency of the facility's existing cooling systems needs to be entered by the user or the user can use the default value. In addition, the capacity of the cooling system is assumed to be fixed to put an upper constraint on the maximum charging capacity of chilled water TES. The default assumption is that the chiller plant cooling capacity is 125% of the peak cooling load. This is a value that the user can adjust.

Cooling system unit power requirements are not adjusted based on cooling loading or outside air conditions. The user's entered coefficient of performance (COP) value is assumed to represent the average system performance throughout the year. The COP includes the power requirements for the compressors/chiller(s) and heat rejection.

The user can use the default COP value if their annual average COP is unknown. The default value depends on the assumed capacity of the cooling system. These are determined by the cooling loads entered by the user and the following assumptions:

- Chillers are water cooled.
- By default, the cooling system's capacity is assumed to be 1.25 times the peak cooling load in the interval data. This value can be modified by the user.
- For peak cooling loads less than or equal to 300 tons, the cooling plant is assumed to have one chiller. For peak cooling loads greater than 300 tons, we assume there are two or more chillers of approximately equal capacity, with no chiller capacity exceeding 800 tons (Pacific Northwest National Laboratory 2016).

The default COP in the bottom row of Table 1 are used as provided (Sweetser 2020).

Table 1. Default COPs for Existing Cooling Plant

	Chiller capacity <= 100 tons	**Chiller capacity > 100 tons**
Chiller power (kW/ton)	0.60	0.55
Condenser heat rejection (kW/ton)	0.20	0.20
Chiller plant total power (kW/ton)	0.80	0.75
Default chiller plant COP (kW thermal/kW electric)	**4.40**	**4.69**

In any hour, the cooling load must be met by some combination of the existing cooling system and the following REopt retrofit technologies: absorption chiller, chilled water TES, and GHP if they are included. Note, GHP is sized and dispatched to serve the total cooling load in every timestep, so if GHP is chosen by the REopt optimization model then there will be no remaining cooling load to serve and therefore will preclude any economic benefit from absorption chiller and chilled water TES.

The model does not include turn-down limits (minimum unloading ratio constraint) on the cooling system.

If chilled water TES is considered, the distribution loop temperature differential is used to estimate the tank's thermal storage capacity. See Section 16.1, Chilled Water Thermal Energy Storage for details.

For centralized chilled water systems, the assumed chilled water loop temperatures are (Pacific Northwest National Laboratory 2016):

- Supply temperature: 44°F
- Return temperature: 56°F.

In a future release, the user will be able to adjust chilled loop temperatures which will only impact the thermal storage capacity of chilled water TES per unit gallon of storage.

5.4 Land and Roof Area Available

Users can specify the amount of land and/or roof area available for DER. Land area available is used to limit the amount of PV or wind recommended at the site; roof area available is used to limit the amount of PV recommended. These inputs do not limit the size of any other technology.

PV size is constrained by land area available, assuming a power density of six acres per MW, and by roof area available, assuming a power density of 10 DC-Watts/ft^2. Wind size is constrained by land area available, assuming a power density of 30 acres per MW for turbine sizes above 1.5 MW. If the turbine size recommended is smaller than 1.5 MW, the input for land available will not constrain the system size. If the turbine size recommended is greater than 1.5 MW, but the land available input is less than 30 acres per MW, then the system size will be capped at 1.5 MW, no matter how small the land available input. It may be wise to run the evaluation with unconstrained land as a check that density constraints are limiting results in the manner expected. The default value is unlimited, meaning PV or wind size is not limited by land or roof area available. Note that both land and roof availability limits should be entered to limit PV size.

Currently, there is no user input field for the space available for a GHP geothermal heat exchanger. The user is advised to review the size of the geothermal heat exchanger in the solution when considering where and how a system could be installed at their facility.

6 Electricity and Fuel Tariffs

This section describes the utility rate tariff inputs to the REopt web tool.

6.1 Electric Rate Tariff

For all evaluations, details of the site's electrical rate tariff must be specified. The electricity rate can be selected from a list of rates available within 25 miles of the user-entered location. The rates are downloaded from the Utility Rate Database (URDB).[6] If available, the most common

[6] https://openei.org/wiki/Utility_Rate_Database

rates are listed at the top of the list. Utility rates that are not in URDB can be modeled as custom rates.

A custom electricity rate can be modeled as an annual, monthly, detailed rate, or URDB label. If the electricity rate will stay constant through the year, select the “Annual” option and enter the $/kWh Energy cost and, if relevant, the $/kW Demand cost. If an “annual” demand charge is specified, it will still be applied on a monthly basis. If the electricity rate varies by month during the year, select the “Monthly” option and enter the $/kWh Energy cost and, if relevant, the $/kW Demand cost that applies in each month of the year.

If you want to use a URDB rate that isn’t available in the dropdown list for your selected location, you can enter a URDB label that corresponds to an unlisted rate. This label can be found in the URL for the URDB rate on the Open EI website. For example, the label for the rate found at the URL https://openei.org/apps/IURDB/rate/view/5e6134175457a3cf56019407 would be entered as just the label **5e6134175457a3cf56019407**.

If the electricity rate varies during a single month, such as a rate with weekday/weekend or time-of-use rate differences, select the Detailed option. You must be registered and logged in to a user account to access this feature. The Custom Electricity Rate Builder will open and allow you to enter different rates for different time periods, along with time and month schedules for applying these period rates. Once you have named, created, and saved detailed custom rates, they will show up in the “Select Custom Rate” dropdown menu on the main input page and they can be selected to be applied to a current optimization. To build a custom rate tariff:

- Start by entering a name for the custom rate. Once you have named, created, and saved detailed custom rates, these names will show up in the "Select Custom Rate" dropdown menu on the main input page and can be selected to be applied to an optimization. An optional description can also be entered in order to assist in identifying a custom rate.
- Enter each separate rate into the Rate Periods tables for both Energy Charges and Demand Charges. If the rate for a time period includes usage tiers, add tier(s) to that period and enter the maximum energy purchases allowed in the tier(s). The final tier will have unlimited maximum usage.
- After you have defined the Rate Periods, use the Weekday and Weekend Schedule Tables to select the months/times when each period applies. When you have selected a block of time cells, a popover will appear with a dropdown menu so that you can select the relevant period for those cells.
- Periods do not have to be sequential; however, tiers within a given period must be sequential.
- An optional fixed monthly charge, in $/day, can be entered in the top section.
- An additional option exists for users who access the REopt tool through the API. A detailed rate can be created then downloaded as a JSON to be used with the API. JSONs can be downloaded from the Custom Electricity Rate Manager. A previously created JSON can also be uploaded for editing and then saving as a new rate.
- An option can be selected to populate the tool’s rates and schedules with an existing URDB rate, which can then be edited and saved as a new rate. The rate location chosen does not need to be the same location as the evaluation’s site location.

- An optional simple Facility Demand Charge can be selected. This monthly/non-coincident/facility demand charge is one value per month, that is charged based on the highest demand of the month, regardless of time of day. This charge is in addition to the TOU demand charge. Also available in this section is a simple lookback percent, or ratchet charge, which considers both the current month and previous months' peaks in the calculation of demand charges.

The Custom Electricity Rate Builder allows for modeling utility rates that do not appear in the URDB. Currently, this option can only be chosen as a substitute for the URDB rates and not as an additional add-on charge to a URDB rate.

The Custom Electricity Rate Manager allows you to view, edit, and copy the detailed custom electricity rates that you have created, or download a JSON version of the rate. *NOTE: Once a custom rate has been used in an optimization, that particular rate can no longer be edited or deleted. However, the rate can be copied to create a new or corrected rate*. The table lists your custom rates in chronological order based on when they were created. The name and description you assigned are listed in the table along with the maximum and minimum charges. If you wish to look at the details of the rates by time period, click on View Charge Periods.

6.1.1 CHP Standby Charge

Standby tariffs for on-site generation are sometimes imposed to cover the utility's cost to provide backup power to the customer for periods of time when the customer's generator might be unavailable due to planned or unplanned maintenance activities. Standby tariffs are not unusual for CHP systems. Sometimes described as 'partial requirements' tariffs, they can take the form of a relatively simple additional charge added to a customer's existing tariff, sometimes described as a 'full requirements' tariff, or can involve switching to an entirely different tariff if CHP is installed. Tariff switching, i.e., modeling both the existing tariff and alternative tariffs that may be activated if the consumer were to install certain types of DG, cannot be modeled in the REopt web tool.[7] However, the user can include potential standby charges that might be imposed if CHP is installed that are added to the existing electricity tariff by using the 'CHP standby charge based on CHP size ($/kW/month)' field in the rate tariff section of the user interface. This option is only available and visible to the user when CHP technology is included.

This optional additional standby charge for CHP includes monthly charges based on the installed power capacity of CHP ($/kW/month of CHP rated capacity). This is a fixed monthly charge dependent on the CHP rated power output. Standby demand charges are entered as a single value and applied monthly ($/kW-month). The default value is $0.

[7] If the standby 'supplemental' tariff cannot be modeled as the standard 'full requirements' tariff plus some combination of the charges described above, the user will have to model the standby tariff in the tariff template instead of the full requirements tariff. The user will have to keep in mind that the financial results are only relevant if CHP is included in the investment scenario returned and that the business-as-usual costs in that solution are not accurate because they are calculated for the standby tariff rather than the non-standby tariff. Further, if the investment scenario also includes PV, wind power, and/or battery, the user should confirm with the serving utility whether the modeled standby tariff applies to the hybrid CHP system.

6.1.2 Exporting to the Grid

By default, the REopt web tool assumes that electricity generated by all DERs except CHP can be exported to the grid. While the value of exported power can be set to zero (by entering a net metering limit and wholesale rate of zero), power can still be exported. It is not uncommon for power export to be prohibited as part of a CHP interconnection agreement with the serving electric utility. In the REopt web tool, this prohibition is the default constraint. The user can remove this constraint by using the 'CHP allowed to export to the grid' check box. Even if there is no compensation from the utility for exported power, allowing export could change the results of the solution because it would allow the CHP system to serve site loads (or net loads if other DER are included) that at times may be below the minimum turndown limit of the CHP prime mover. See Section 14, Combined Heat and Power for more information on CHP minimum turndown limits.

6.1.3 Net Metering

Net metering policies provide credits to utility customers for approved customer generation that exports energy to the grid. The net metering limit determines the maximum size of total combined systems that can be installed under a net metering agreement with the utility. Projects sized up to the net metering limit will receive credit for any exported energy at the electric retail rate at the time of export. Projects sized greater than the net metering limit will receive credit at the wholesale rate for any energy exported.

Information on state net metering limits is available at www.dsireusa.org. The user is not required to enter a value for this input. By default, the REopt web tool assumes that net metering is not available (net metering limit = 0).

The user can select whether PV, wind, and CHP are eligible for net metering, and the combined electric capacity of all those systems is used for the net metering limit.

6.1.4 Wholesale Rate

The wholesale rate for exported energy applies to projects that are not net metered or projects sized greater than the net metering limit. If a wholesale rate is entered and net metering is not available (i.e., net metering size limit is 0 kW) or if the project is sized greater than the net metering limit, then the project will receive credit for any exported energy at this wholesale rate, up to the annual site load so that the site does not become a net exporter of electricity.

6.2 Fuel Costs

Fuel costs are entered for analyses that include CHP and GHP. The fuel type and fuel costs must be entered for both the existing heating system and for the CHP if screened. Fuel types are used to track CO2 emissions associated with their consumption. No other defaults, including CHP prime mover performance and costs, are adjusted when the user changes the fuel type from the natural gas default.

Fuel costs can be entered as a single annual value or as a monthly value. The units are \$/MMBtu based on the HHV of the fuel.

6.3 Solver Settings

The solver optimality tolerance is an input that can be adjusted for evaluations that result in a timeout error message because they are not reaching a solution within the time allowed. It is the threshold for the difference between the solution's objective value (life cycle cost) and the best possible value (lower bound of the objective function as determined by the optimization model) at which the solver terminates. Note, there is no guarantee that the best possible value would be achieved if the model ran longer. It's possible that the solution achieved within the optimality tolerance is the same solution that would be found if the model ran indefinitely.

It is suggested to increase this value to 2-3% if no solution is found within the model's timeout limit. Increase the value further if the model still times out. The maximum allowed tolerance value is 5%. Once a solution is found with the higher tolerance, the user could choose to bound the technology sizes using the minimum and maximum size inputs and run the model with a lower tolerance.

7 Loads

This section describes the required load inputs. Because the REopt web tool models a full year, the model requires typical load values for every hour of the year. If finer interval data is available, e.g., 15-minute interval data, the user can input that data and the REopt web tool user interface will down-sample it to 1-hour intervals. If running the API directly, the user can run at 15-minute, 30-minute, or 1-hour interval length. Because only one year of load is modeled, the implicit assumption is that the load does not change significantly from year to year over the analysis period.

For PV, wind, and battery storage analysis, only electricity loads are needed. For CHP and GHP analysis, heating loads are also required. If the user considers chilled water TES or absorption chillers, cooling load interval data is also required.

7.1 Actual (Custom) Load Profile

If available to the user, the user uploads actual interval load data for the facility. In the REopt web tool user interface, this is called a custom load profile. Actual load data will result in the most accurate results. If "Upload" is selected, the user must upload one year (January through December) of hourly, 30-minute, or 15-minute load data, in kW, by clicking the browse button and selecting a file. A sample custom load profile[8] is available, which includes an optional header and optional additional column A with the 8,760 hour-long intervals listed for reference.

The file should be formatted as a column of 8,760, 17,520, or 35,040 rows. The file should be saved as a .csv file. If the file does not contain the correct number of rows (8,760, 17,520, or 35,040), or there are rows with blank entries, the user will receive an error message.

In the web interface, the option to use 15-minute or 30-minute load data is provided for user convenience, not for higher model resolution. If 15-minute or 30-minute data is uploaded, it will

[8] https://reopt.nrel.gov/tool/load_profile_template.csv

be down-sampled to hourly data for the evaluation. In the API, the user can run sub-hourly analysis.

If the load profile is from a leap year, where an extra day's worth of data is part of the file, the December 31 data should be deleted so that the file will be the correct length. Deleting December 31 will have the least impact on the evaluation results. The February 29 data should not be deleted, because it would impact the day of the week status for all days from March to December, and many utility rates have different rates for weekdays and weekends. The calendar year the load profile represents is entered in the 'Year of load profile' field. This information is needed to correctly apply tariffs that vary by days of the week. The default for this input is the current year.

7.2 Simulated Load Profile from Models

If actual interval data is unavailable, the user has access to 16 load profiles from DOE Commercial Reference Building (CRB) models that can be used either to analyze one or a mix of the standard building types or to synthesize user-entered annual or monthly total values into hourly load profiles (see Table 2). The climate for CRB loads is selected based on the user's entered location (see Table 3). In addition to using these load profiles, the user can model flat or constant loads. In the user interface, loads generated with CRB models and flat load options are called Simulated Load Profiles.

The loads are generated from DOE's post-1980 CRB models assuming ASHRAE 90.1-1989 building energy code for the climate zone of the site using EnergyPlus® simulation software. The simulated load profile is created for a generic year that starts on Sunday. Because January 1, 2017 is a Sunday, 2017 shows as the load year when using CRB loads. If the user uses Simulated Load Profiles and overwrites the default Annual Energy Consumption displayed in the interface for the selected building type model, the Simulated Load Profile will be scaled to match the user's Annual Energy Consumption value. This is useful when the user has total annual energy consumption but requires use of the CRB hourly interval load values to synthesize interval data. The user can select to enter energy totals by month and the CRB hourly interval data will instead be scaled to match the monthly totals entered. The building chosen for the electric load simulation does not need to be the same building type chosen for the heating or cooling loads.

Table 2. DOE Commercial Reference Building Types

Building Type	Floor Area (ft^2)	No. of Floors
Large Office	498,588	12
Medium Office	53,628	3
Small Office	5,500	1
Warehouse	52,045	1
Stand-alone Retail	24,962	1
Strip Mall	22,500	1
Primary School	73,960	1
Secondary School	210,887	2
Supermarket	45,000	1
Quick Service Restaurant	2,500	1
Full-Service Restaurant	5,500	1
Hospital	241,351	5
Outpatient Health Care	40,946	3
Small Hotel	43,200	4
Large Hotel	122,120	6
Midrise Apartment	33,740	4

Source: https://energy.gov/eere/buildings/commercial-reference-buildings

Table 3. Climate Zones

Climate Zone	Representative City
1A	Miami, Florida
2A	Houston, Texas
2B	Phoenix, Arizona
3A	Atlanta, Georgia
3B-Coast	Los Angeles, California
3B	Las Vegas, Nevada
3C	San Francisco, California
4A	Baltimore, Maryland
4B	Albuquerque, New Mexico
4C	Seattle, Washington
5A	Chicago, Illinois
5B	Boulder, Colorado
6A	Minneapolis, Minnesota
6B	Helena, Montana
7	Duluth, Minnesota

Climate Zone	Representative City
8	Fairbanks, Alaska

Dropdown menu options include the 16 modeled building types and flat load options—for a site with a relatively constant electric load. Flat loads are meant to approximate the hourly load(s) using average energy consumption values. These flat loads are based on different operating schedules (hours per day / days per week) listed below. The values for annual or monthly energy are spread out evenly throughout the days/hours included in the description of each load below:

- 24/7 – constant load for all days/hours of the year (truly “flat”)
- 24/5 – all hours of the weekdays
- 16/7 – two 8-hour shifts for all days of the year; 6–10 a.m.
- 16/5 – two 8-hour shifts for the weekdays; 6–10 a.m.
- 8/7 – one 8-hour shift for all days of the year; 9 a.m.–5 p.m.
- 8/5 – one 8-hour shift for the weekdays; 9 a.m.–5 p.m.

The annual or monthly energy values for these flat loads are expected to be entered by the user; however, the model provides default annual energy load values which is the average of all the CRB types for a given climate zone.

7.2.1 Modeling a Campus with Multiple Simulated Building Load Profiles

The user can choose multiple commercial reference building types to model a space with mixed-use or multiple buildings on a campus. If “Simulate Campus” is selected, an annual electric consumption for the entire campus is entered along with up to five building types and the percentage of that annual total energy consumption that each of the building types is expected to consume. The simulated load for each building type will be scaled based on the percentage of the annual energy consumption entered. The REopt web tool will use the resulting blended simulated electric load profile in determining a single optimally sized energy system for the entire campus.

7.3 Electric Loads

The electric interval data entered or generated with CRB models is the facility’s total electric consumption through the utility meter that DER could offset. There is no cost function for integrating multiple metering points within a facility and therefore it is assumed the loads entered are for a single electric meter and are addressable by DER. The units for electric interval load are kW. The units for Annual Energy Consumption and Monthly Energy Consumption are kWh.

7.3.1 Electric Load Adjustment

Users can adjust the electric load profile up or down by a specified percentage using the electrical load adjustment slider. The default value is 100% of the entered load, meaning no adjustment will be made. Entering a value greater than 100% will increase the load in each timestep. Entering a value less than 100% will decrease the load in each timestep. The adjustment applies to all three methods of entering the typical load, including simulate building, simulate campus, or upload. The adjusted load will be used in the optimization and the results will be based on the adjusted load. This feature can be used to reflect the impact of energy efficiency measures that may reduce the electric load, or new construction that may increase the electric load. For a resilience analysis, adjustments made to the typical load through the load adjustment slider are also applied to the critical load if the "percent" critical load factor option is selected. If the "upload" or "build" option for the critical load is selected, the adjustment made to the typical load through the load adjustment slider will apply only to the typical load and will not change the uploaded or built critical load.

7.4 Heating Loads

The heating load can include space heating, domestic hot water, industrial heating, and, if considering CHP, any high-temperature thermal energy provided to the absorption chiller if by CHP.

The entered heating load interval data has units of fuel (MMBtu of fuel/hour, HHV-basis). Units of fuel, rather than heat, are used since it is assumed that the user is likely to have total fuel consumption from utility bills or invoices and will use CRB modeled heating loads to synthesize hourly interval data that matches the user-entered total fuel consumption. Fuel loads are converted to thermal values (heat) using the heating system thermal conversion efficiency. The resultant heating loads are gross loads on the plant; therefore, heat for a boiler deaerator makeup water and heating losses in the distribution piping are included.

By default, the model assumes the entire heating (fuel) load entered can be served by (is addressable by) the CHP system. If some of the total heating load is not addressable by CHP (for example, it is used for cooking or other processes that are not served by the heating loop), the user can include a value for Addressable load percent (%) between 0 and 100% (single value for annual fuel energy or monthly values for monthly fuel energy. For GHP, the default assumption is that only space heating, not domestic hot water (DOMHW), is supplied by heat pumps. However, the user interface includes a toggle if the domestic hot water heating loads are also to be served by GHP.

If GHP is not to serve domestic hot water, the determination of the split of fuel used for space heating and DOMHW depends on how the user enters the heating system fuel load. If the user enters annual or monthly gas usage and leverages the CRB models to synthesize the hourly loads, REopt parses the fuel for space heating and DOMHW using the hourly fractions from the CRB model. If the user enters their own hourly interval data or uses a flat load, the current assumption is that the fuel for space heating and DOMHW is split 50/50. A future improvement will allow the user to specify their own fraction of fuel that is used for space heating, and the remainder will be used for DOMHW. As a workaround, if the intention is to model a custom heating load that represents only space heating, the user should check the box for "Heat pump can serve the domestic hot water load" in the GHP accordion which will assume all of the user-entered heating load can be served by GHP.

Simulating a campus for the heating load is similar to what is described in Section 7.2.1 for the electric load; the user enters the annual fuel energy and the mix of buildings to shape the heating load profile.

7.5 Cooling Loads

The electrical consumption of the cooling system is assumed to be included within the total facility electric load (i.e. it is a *subset* of the total facility electric load). However, if the user is interested in modeling GHP, chilled water TES, or absorption chillers, the cooling load must be explicitly defined. The user has several options for specifying the cooling load that differ slightly from the total facility electric load and the heat load:

1. Specify the building type(s) **only** (without annual or monthly cooling thermal energy values) using the *Simulate Building* or *Simulate Campus* tabs

    a. This uses simulated building's hourly profile of *fraction of total facility electric load* that is allocated to cooling. The cooling electric profile is converted to a cooling thermal profile using the cooling system COP.

2. Specify the building type(s) **and** the amount of cooling thermal energy delivered by the cooling system using the *Simulate Building* or *Simulate Campus* tabs.

    a. This generates the hourly cooling thermal profile using the analogous method to total facility electric and heating load described above but with annual or monthly cooling thermal energy.

    b. **WARNING**: this method has a risk that the cooling-based electric load (converted from the user-entered cooling thermal load) **exceeds** the total facility electric load during certain hours of the year, which is non-sensical. However, the user will get an error immediately that specifies which hours of the year this occurs, and if this happens it is suggested to check the cooling thermal energy inputs and compare to the total facility electric load in more detail.

3. Specify an annual or monthly fixed percentage of total electric load (%) using the *Custom* tab.

    a. This applies the fixed percentage to the total facility electric load for each hour of the year (annual fixed percentage) or month (monthly fixed percentage), and it then converts the load to a thermal load using the cooling plant COP.

The *Upload* tab is used if the existing hourly cooling system thermal load (units of tons of cooling) is available. The associated electricity consumption is calculated using user-entered or default cooling system COP value. As described in Section 5.3, the COP is inclusive of the heat rejection electricity requirements.

We assume cooling losses in the distribution system are captured in the entered cooling load; losses in distribution are not separately modeled.

8 Resilience Analysis

By default, the REopt web tool optimizes systems to maximize grid-connected economics. Users have the option of specifying additional resilience requirements to design a system that will also sustain a critical load for a specified outage period. Currently, the REopt web tool can only model one outage period per year.

8.1 Critical Load

The critical load is the load that must be met during a grid outage. It can be calculated as a consistent percent of the typical load profile that is being used, uploaded as a separate custom load profile, or built specifically to correspond to important loads at the site.

If “Percent” is selected, the critical load is a percentage of the typical load profile. This factor is multiplied by the typical load to determine the critical load that must be met during the specified outage period. If “Upload” is selected, the user can upload one year of hourly, 30-minute, or 15-minute critical load data. If “Build” is selected, the user can create a custom critical load profile based on specified load components. Only the one active option for specifying the critical load will be applied to the optimization.

8.1.1 Critical Load Builder

The Critical Load Builder allows you to create a daily emergency load profile by building a list of equipment that is critical at your site—along with wattage, quantity, daily operation hours, and annual operation months. Once you have named, built, and saved critical load profiles, they will be available for selection from the Critical Load Profile dropdown menu on the main input page, and can be used in an optimization. You must be registered and logged in to a user account to access this feature. This tool is based on SolarResilient, a tool developed by Arup, under contract to the City and County of San Francisco, with funding from DOE.

To build a new critical load profile, the registered and logged-in user can click the “Build New Critical Load Profile” link and build a new load in the resulting pop-up window while retaining the other inputs already entered. Alternatively, the user can click “Build, copy, and manage your critical load profiles” below the blue box, or “Critical Loads” in the top right-hand corner of the webpage and be taken to a different page to either copy and edit a previously built critical load or to build a new critical load profile from component electrical loads. If the user chooses either of these options, a new evaluation must be started and all inputs that had been entered for the current optimization will need to be re-entered.

To build a critical load profile:

- Start by entering a name for the Critical Load Profile. Once you have named, built, and saved critical load profiles, they will be available for selection from the Critical Load Profile dropdown menu on the main input page, and can be used in an optimization.
- Select load components from the dropdown list. The load component will populate with default suggestions for the power, hours, and months.
- Once added, you can edit the details of the load component to better simulate your critical load conditions.
- Add as many load components as necessary. The last load in the dropdown menu is a custom load, which can be used as a starting point to add components that are not in the menu.

Note that these components are being modeled as flat loads at user-specified power and operation times. There is no cycling, for example, on the air conditioner or space heater. The load does not change based on the weather or room temperature.

Load Type

Select a preexisting load type and add the load component to your new critical load profile. Once added, you can edit the details of the load component to best simulate your critical load conditions. Add as many load components as necessary.

Power (W)
This is the power requirement for the selected load type. Default values are taken from Lawrence Berkeley National Laboratory's Home Energy Saver Engineering Documentation,[9] ENERGY STAR Certified Product data sets,[10] and the DOE Appliance and Equipment Compliance Certification Database.[11] Many appliances have the wattage stamped on the unit, representing the maximum power drawn by the appliance. The wattage can also be estimated by multiplying the electric current draw, in amperes, by the voltage used by the appliance (typically 120 volts). Amperes may be stamped on the unit or listed in the owner's manual. Energy.gov also provides a calculator for estimating appliance and electronic energy use.[12]

Start Hour
Start hour is represented similar to military time. For example, 0 represents 12 a.m. and 16 represents 4 p.m. To simulate a component that would run all day, the start hour would be 0 and the end hour would be 24. To simulate a component that runs from 3 a.m. to 5 p.m., the start hour would be 3 and the end hour would be 17. The start hour must be a whole number and cannot be greater than 23 (representing 11 p.m.).

End Hour
End hour is represented similar to military time. For example, 1 represents 1 a.m., 13 represents 1 p.m., and 24 represents 12 a.m. **on the following day**. To simulate a component that would run all day, the start hour would be 0 and the end hour would be 24. To simulate a component that runs from 3 a.m. to 5 p.m., the start hour would be 3 and the end hour would be 17. The end hour must be a whole number and cannot be less than 1 (representing 1 a.m.).

End Month
To specify a load component duration of one month, select the same start month and end month. The year of the custom critical load profile is assumed to be the same as the year set for the custom load profile.

The Critical Load Profiles summary allows you to view, edit, and copy the critical load profiles that you have built. The table lists your critical load profiles in the chronological order in which they were created. The name and description you assigned are listed in the table along with the minimum, average, and maximum loads. The dates for the minimum and maximum load values refer to the first chronological instance of that minimum or maximum load. If you wish to look at the details of the critical load profiles by time period, click on the icon to view load profile components. Icons are also available to chart or download the critical load profile. Once a critical

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[9] http://hes-documentation.lbl.gov/calculation-methodology/calculation-of-energy-consumption/major-appliances/miscellaneous-equipment-energy-consumption/default-energy-consumption-of-mels
[10] https://www.energystar.gov/productfinder/advanced
[11] https://www.regulations.doe.gov/certification-data/products.html#q=Product_Group_s%3A*
[12] https://www.energy.gov/energysaver/save-electricity-and-fuel/appliances-and-electronics/estimating-appliance-and-home

load profile has been used in an optimization, that particular load profile can no longer be edited or deleted. However, the load profile can be copied to create a new or corrected load profile.

8.2 Outage Start Time and Duration

The user specifies the outage period that the system must sustain by specifying the outage start date, time, and duration (number of hours). The system will be sized to minimize the life cycle cost of energy, with the additional requirement that it must also sustain the critical load during the outage period specified. The outage duration must be a number between zero and 8,759.

In general, selecting an outage start date when the site's load is higher (often summer) will result in larger system sizes that can sustain the critical load during more outages. Selecting an outage period during a time of year when the site's load is lower will result in smaller system sizes that sustain the critical load during fewer outages. However, solar and/or wind resource will also impact the resiliency of the system. The user can choose to automatically populate the outage start date and time with the date and time of the maximum load hour using the "autoselect using critical load profile" link.

For the calculations made in the Effect of Resilience Costs and Benefits section, where avoided outage costs and NPV after microgrid costs and benefits are presented, the outage event is assumed to occur every year of the analysis period. This assumption does not impact the optimization results or NPV calculation for the project.

For information on typical outages in the United States, the user can check Electric Power Monthly, the U.S. Energy Information Administration's compilation of the location, duration, and description of major electric disturbances by month.

9 Renewable Energy and Emissions

The REopt web tool provides metrics on renewable energy (RE) usage and estimates of emissions associated with a site's energy consumption. Calculations are performed for both the Business-as-Usual case and the Optimal (Investment) case to help quantify the emissions and RE impacts of DERs.

In the web tool, the "Renewable Energy and Emissions Accounting" accordion contains modifiable default values for RE and emissions. RE inputs include renewable content of fuels burned on-site and an option to include or exclude exported renewable electricity in the renewable electricity totals. Emissions inputs include emissions factors for grid-purchased electricity and fuels burned on-site, emissions costs, and an option to count exported electricity as emissions offsets. For all analyses, the REopt tool will determine the monetary impact of a site's emissions on climate and public health. Users can additionally choose to include climate and/or health costs in the REopt objective function and net-present value calculation, thus allowing these costs to impact the optimal system sizing and dispatch.

In addition to calculating emissions and renewable energy impacts of DER investments, users can also define clean energy targets. When the "Clean Energy" button is selected, a user can add renewable electricity or emissions constraints to the REopt optimization model.

The sections below detail the REopt tool's renewable energy accounting, emissions accounting (calculations and costing of emissions), default data sources for grid and fuel emissions factors, and user-defined clean energy constraints.

9.1 Renewable Energy Accounting

The REopt web tool calculates the quantity and proportion of the electricity and heating loads (both of which also may support cooling loads) served by renewable energy in the Business-as-Usual case and the Optimal (Investment) case. Table summarizes how each technology may be considered to provide renewable electricity or heat. For technologies that generate both electricity and heat, the renewable energy factor (*REF*) is assumed to apply to both its electricity generation and its heat generation. Grid electricity is not currently ascribed any renewable energy attribute.

Table 4. Renewable energy contributions by technology

Technology	Percent of generation assumed renewable ("Renewable energy factor (REF_t)")	Generates electricity, heat, or both?
Solar PV	100%	Electricity
Wind	100%	Electricity
Backup generator	User-input (0-100%), based on percentage of fuel classified as renewable	Electricity
Boilers	User-input (0-100%), based on percentage of fuel classified as renewable	Heat
CHP	User-input (0-100%), based on percentage of fuel classified as renewable	Both electricity and heat
Steam turbine	Calculated (0-100%) based on source(s) of steam; depends on what portion of the steam used to power the steam turbine is generated from renewable fuels	Both electricity and heat
GHP	Calculated (0-100%) based on fraction of electricity derived from renewable generation	Heat

Note that these renewable energy factors are distinct from, and not applied to, emissions factors or calculations. Fuel emissions factors should be entered after considering any renewable composition of the fuel and whether or not the user wants to include emissions associated with combustion of renewable fuels. For instance, if a site burns fuel that is 10% from landfill gas and enters 10% renewable fuel as an input, the emissions rate input by the user is *not* decreased by 10%. Renewable energy outputs include:

- **Percentage of annual electric load served by renewable electricity:** Annual renewable electricity consumption is calculated as total annual onsite renewable electricity generation, minus battery storage losses and considering curtailment, with the user selecting whether exported renewable electricity is included or excluded from the total (see below). Note that this includes any renewable contributions to electric heating (i.e., GHP) and/or cooling (i.e., electric chiller, absorption chiller) loads. This value is then divided by total annual electric load, also including any electric heating and cooling loads.

  - Note: Users can decide whether to include excess renewable electricity generation that is exported to the grid as contributing to site renewable energy (and/or emissions) totals. Some policies assign renewable energy attributes of onsite generation exported to the grid to the host site, but in some regions those renewable energy attributes go to the utility, especially if the site is compensated for the generation via net metering or an avoided cost payment. Additionally, for third party financing arrangements, some state and utility policies assign renewable energy attributes to the developer rather than the host site/off-taker. The user should research policies applicable to their site in making this selection.

- **Percentage of total annual energy consumption (electric loads plus steam/hot water thermal loads) served by renewable energy:** The numerator is calculated as total annual renewable electricity consumption (see above) plus total annual thermal energy content of steam/hot water generated from renewable fuels (non-electrified heating loads). The thermal energy content is calculated as total energy content of steam/hot water generation from renewable fuels, minus waste heat generated by renewable fuels, minus any applicable hot water thermal energy storage efficiency losses (decay rate not considered). The denominator is calculated as total annual electric load (including electric heating (i.e., GHP) and/or cooling (i.e., electric chiller, absorption chiller) loads) plus total annual thermal steam/hot water load (including steam for absorption chiller).

  - Note: In cases involving steam turbines, some fuel-burning technologies (boiler and CHP) can provide steam to the steam turbine. In calculating annual steam load (and contribution of renewable energy to this steam load), the thermal energy content of the steam feeding the steam turbine is not included in the total steam load as some of it may be used to produce electricity, but thermal output from the steam turbine is included.

Both the renewable electricity and renewable energy percentage outputs focus on annual consumption rather than annual generation. Renewable content of generation which will always be greater than or equal to that of consumption depending on technology performance and efficiency losses. This decision was intended to avoid double-counting of energy consumption by technologies operating at the intersection of electricity and thermal consumption or generation.

In cases involving GHP, converting a heating source from fuels to electricity increases electricity demand and decreases steam/hot water heating loads (and fuel consumption). Thus, the renewable heat output is inclusive of the renewable electricity used to power GHP, so the two values (renewable heat and renewable electricity) are not additive in cases involving GHP. (They are additive in all other cases.)

Unlike emissions accounting options, no dollar value (e.g., $/kWh$_{RE}$ or $/MMBTU$_{RE}$) is attributed to overall renewable energy generation. Instead, users can enter a production incentive for a specific technology (e.g., $/kWh for PV generation).

9.2 Emissions

The REopt web tool estimates climate impacts of carbon dioxide (CO_2) and health impacts of nitrogen oxides (NOx), sulfur dioxide (SO_2), and primary particulate matter 2.5 microns or less in width (PM2.5). While greenhouse gases other than CO_2 (such as methane and nitrous oxide) increase radiative forcing, their collective CO_2-equivalent impact is relatively small for the electricity sector; by review of EPA's eGRID tables, the difference in grid-sourced electricity emissions factors for CO_2 and CO_2e is 1% for Northeast Power Coordination Council (NPCC) New England and less than 1% for all other regions. NOx, SO_2, and primary PM2.5 affect human health through their secondary formation of ambient PM2.5. Together, these species account for approximately 96% of the increase in PM2.5 exposure, and associated increase in premature mortalities, from the electricity sector (Deddousi & Barrett, 2014). In 2018, approximately 8,500 early deaths were attributable to emissions from electric power generation (Dedoussi, Eastham, Monier, & Barrett, 2020).

9.2.1 Emissions Factors and Default Data

This section describes data available for grid and fuel emissions factors, along with REopt web tool defaults.

9.2.1.1 Grid Emissions Factors

Emissions accounting is intended to estimate the change in emissions that results from adoption of DERs. When assessing a *change* in grid purchases, particularly when the change is small relative to total grid load, it is most appropriate to use marginal, rather than average, grid emissions factors (Ryan, Johnson, & Keoleian, 2016). Marginal emissions factors quantify the change in grid emissions that result from a marginal change in grid-purchased electricity (lb emissions/kWh), answering the question "By how much would grid emissions decrease with a reduction in my site's grid consumption?" Average emissions factors are the total emissions divided by total grid generation over a given timeframe. Since marginal (or peaker) generators tend to be more emissions-intensive than baseload or variable generation, marginal emissions factors tend to be slightly higher than average emissions factors.[13] Average emissions factors are often used for baselining or creating an emissions "footprint" of a facility's energy consumption.

For site locations in the continental United States, the default grid emissions factors in the REopt web tool are hourly marginal emissions factors for the EPA AVERT region corresponding to the site's location (EPA 2019).[14] AVERT does not have hourly emission factors for Hawaii and Alaska. If the site is in Hawaii or Alaska, the default values will be annual emissions factors from the EPA eGRID database (EPA 2021). All default emissions factors (AVERT for continental U.S. and eGRID for Hawaii and Alaska) account for transmission and distribution

[13] Note that although the REopt tool defaults to marginal emissions factors calculated from AVERT, some emissions reporting protocols such as the Greenhouse Gas Protocol specifies that organizations should use average emissions factors from eGRID for emissions reporting.
[14] A 1 MW load is entered into the AVERT spreadsheet for every hour of the year on the 'Enter EERE data' tab (1 is entered in "Reduce each hour by constant MW", cell G17).

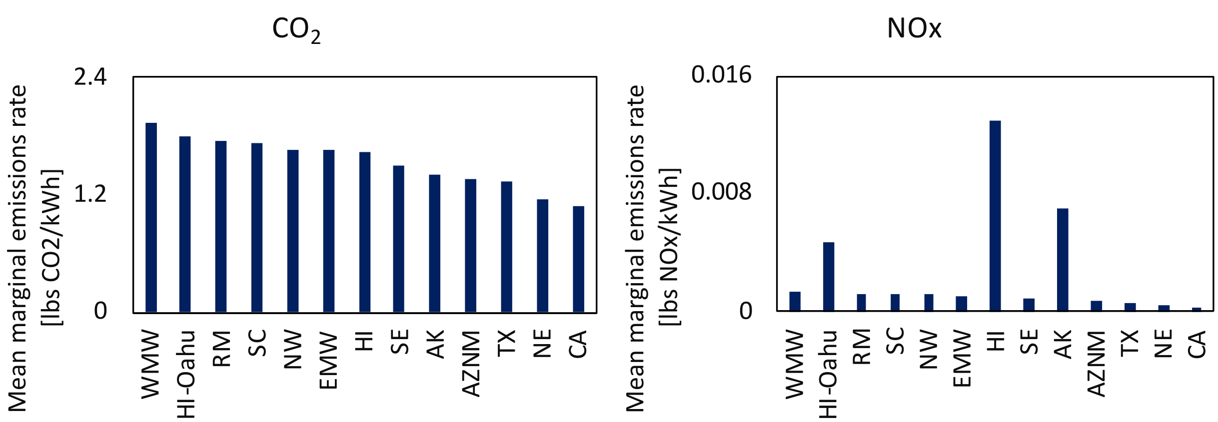
(T&D) losses. Emissions reporting protocols specify whether T&D losses can/should be included in grid emissions accounting; users should research whether these should be included or excluded for their specific use case.

For Alaska and Hawaii, we use eGRID's 'non-baseload' emission rates, which most closely emulate marginal emissions factors. The non-baseload emissions factors are adjusted to account for subregion-specific T&D losses. The resulting emission rates from eGRID for Alaska and Hawaii are in Table 5. The annual average of the default marginal emissions rates for each region are in Figure 2.

Table 5. EPA eGRID emission factors, EF_g, for Alaska and Hawaii

State		Alaska	Hawaii, excluding Oahu Island	Hawaii, Oahu Island
eGRID Subregion Acronym		AKGD	HIMS	HIOA
eGRID Subregion Name		ASCC[b] Alaska Grid	HICC[c] Miscellaneous	HICC Oahu
T&D Losses		5.40%	5.50%	5.50%
eGRID Subregion Annual Emission Rate with T&D Losses	**CO_2 [lb/kWh]**	1.405	1.634	1.798
	NO_x [lb/kWh]	0.007	0.013	0.005
	PM2.5 [lb/kWh]	N/A	N/A	N/A
	SO_2 [lb/kWh]	0.00089	0.0056	0.0086

a. Data from eGRID2019 Data File
b. Alaska Systems Coordinating Council
c. Hawaiian Islands Coordinating Council



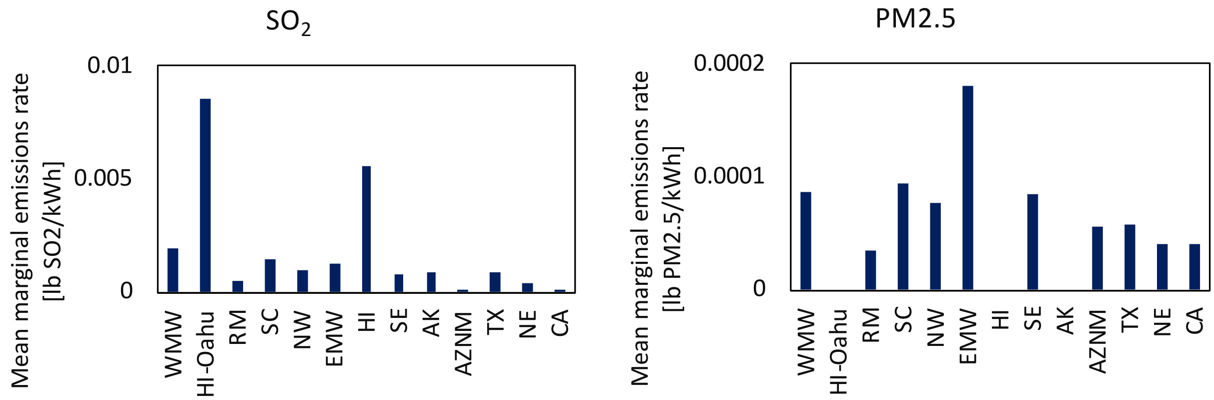


Figure 2. Annual average of the default hourly marginal emissions factors for CO_2, NOx, SO_2, and PM2.5 for grid electricity in each AVERT or eGrid subregion used in REopt

. (AVERT Regions: Upper Midwest (WMW), Rocky Mountains (RM), Lower Midwest (SC), Northwest (NW), Great Lakes / Mid-Atlantic (EMW), Southeast (SE), Southwest (AZNM), Texas (TX), Northeast (NE), California (CA); eGrid Regions: Hawaii, Oahu Island (HI-Oahu), Hawaii, excluding Oahu Island (HI), Alaska (AK))

As an alternative to the default emissions factors or for sites outside of the United States, users can enter a single annual grid emissions rate or custom hourly profiles for each emissions species in lbs/kWh. The single annual grid emissions rate is applied to grid-sourced electricity in each hour of the year. The custom hourly profiles should include columns corresponding to CO_2, NOx, SO_2, and PM2.5. All user-entered emissions factors should include T&D losses. If default values are not available for a given location and no emission rate selection is made, emissions from the electricity grid will not be calculated.

The grid's generation mix is expected to evolve (become cleaner) over time, and thus marginal emissions factors will likely decrease over the analysis period. The default projected annual percent decrease in grid emissions factors (1.174%/year) is calculated as the U.S. national average percent decrease in short-run marginal CO_2 emissions from 2020-2046 based on data from NREL's Cambium Mid-Case scenario (Gagnon, Frazier, Hale, & Cole, 2020). Similar forward-projected emissions factors do not yet exist for health emissions (NOx, SO_2, and PM2.5) and we thus use the CO_2 annual change to approximate the annual percent decrease for health-related emissions. In the REopt API, a user can enter separate percent decrease values for all species.

A note on interpreting emissions results:

If marginal grid emissions rates are used (default rates are marginal) then the "Difference" column in the Results Comparison and Clean Energy Outputs tables accurately captures the change in emissions-related metric tons and cost outcomes. The metrics in the "Difference" column account for how the grid responds to a small change in load: by increasing or decreasing output of the marginal generators. However, care should be taken in interpreting emissions and emissions cost totals for the "Business-as-Usual," "Financial," and "Resilience" cases. The emissions and emissions cost totals for each of these cases in isolation only represent emissions impacts *if* you assume that the load in the Business-as-Usual, Financial, and Resilience cases is powered by marginal generators. Conversely, if average grid emissions rates are used, then emissions results in the "Difference" column may not accurately represent the grid's response to a marginal change in load. Users should refer to any applicable reporting protocols for guidance on which emissions type (marginal or average) to use for their analysis and for guidance in interpreting REopt's emissions results.

9.2.1.2 Fuels Emissions Factors

Emission factors for on-site fuel consumption default to the assumed value for the user-selected fuel type as shown in Table 6.

Table 6. Default Fuel-Specific Emissions Factors used in REopt

Fuel Type	Applicable technology	CO_2 Emissions Factor	NOx Emissions Factor	SO_2 Emissions Factor	PM2.5 Emissions Factor
Natural Gas [lb/MMBtu]	Boiler, CHP	116.9[a]	0.0914	0.000579	0.00733
Landfill gas, other biomass gases [lb/MMBtu]	Boiler, CHP	114.8[b]	0.14	0.045	0.02484
Propane [lb/MMBtu]	Boiler, CHP	138.6[b]	0.153	0	0.00991
Diesel fuel, NO. 2 [lb/MMBtu]	Boiler, CHP	163.1[b]	0.56	0.289	0
Diesel [lb/gallon]	Generator	22.51	0.0776	0.0400	0

a. EPA 2015
b. EPA 2018

CO_2 emissions factors in Table 6 for each fuel type are obtained from the EPA. NOx, SO_2, and PM2.5 emissions factors for each fuel type were calculated from the EPA WebFIRE database (U.S. Environmental Protection Agency, n.d.). Fuel-specific emissions factors were filtered to exclude technologies not modeled in REopt, as well as very large system sizes not expected to be used in most commercial applications. Entries in the database with data quality "U", indicating an unverified emissions rate, were also removed. Commercial/Institutional values were used where applicable. The fuel- and species-specific average of the resulting emissions factors are used as the default values (Table 6). These averages encompass multiple control types and technology types. While CO_2 emissions factors are primarily dependent on fuel type, NOx, SO_2, and PM2.5 emissions factors vary by specific technology and emissions controls. Because these differences are not captured in the REopt defaults, users should supply emissions factors specific to their technology options whenever possible.

9.2.2 Emissions Costs

REopt includes options to include a climate cost of carbon dioxide emissions, called the social cost of carbon dioxide emissions, and health costs of other pollutants. A user may enter a cost per metric ton(t) associated with climate (CO_2) and health (NOx, SO_2, and PM2.5) emissions from grid electricity and on-site fuel burn.

The default value of \$51/t CO_2 (in \$2020) is the average social cost of CO_2 using a 3% discount rate as determined by the U.S. Interagency Working Group on Social Cost of Greenhouse Gases (Interagency Working Group on Social Cost of Greenhouse Gases, United States Government, 2021). This monetary value captures climate change impacts of CO_2 emissions, including (but not limited to) changes to net agricultural productivity, property damage from increased flood risk, disruption of energy systems, and changes to the value of ecosystem services. We calculate the average annual percent increase in the nominal social cost of CO_2 (4.02%/year, nominal) as the compound annual growth rate (CAGR) of the Interagency Working Group's forward-projected costs.[15]

Marginal health costs of emissions are dependent on the local population, atmospheric conditions, and the height from which emissions are released (Heo, Adams, & Gao, 2017). We therefore provide separate health cost inputs for on-site fuel burn and grid emissions. The default marginal health costs are annual averages from the extensively-validated Estimating Air Pollution Social Impact Using Regression (EASIUR) model, as cited in multiple sources (Heo, Adams, & Gao, 2017), (Vaishnav, Horner, & Azevedo, 2017) and (Sergi, et al., 2020). EASIUR is a reduced-form air quality model that estimates the increase in premature deaths caused by an increase in PM2.5 precursor emissions (including NOx, SO_2, and primary PM2.5) in a given location. The EASIUR model estimates health costs across the continental United States and parts of Canada and Mexico at a spatial resolution of 36 km x 36 km.

The default marginal emissions health costs in REopt assume emissions occur at the building location, with grid emissions released at 150 meters above ground (emulating a smokestack) and on-site fuel burn emissions released at ground level. We assume a population and emissions year of 2020 and adjust the marginal costs to $2020. We calculate the annual percent increase in the marginal health costs of NOx, SO_2, and PM2.5 as the CAGR of the EASIUR marginal health costs at the site's location for income and population years of 2020-2024, assuming emissions released from 150 meters (2024 is the last year for which data are available in the reference). These values are in $2010 (therefore the CAGR is a real rate) and the costs are linear with respect to time. We adjust the real CAGR to the nominal CAGR using an assumed average inflation rate equal to the O&M cost escalation rate.[16]

9.3 Emissions Accounting

We calculate CO_2, NOx, SO_2, and PM2.5 emissions of the Business-as-Usual Case (before investment scenario) and Investment Case, which could include a combination of technologies including PV, wind power, battery, diesel generator, CHP, and CHP-enabling technologies of TES and absorption chillers. The difference between the emissions of the Business-as-Usual Case and the Investment Case is the net emissions avoided (or gained). Avoided emissions are calculated for Year 1 of operations as well as for the analysis period. Avoided emissions costs are determined for the analysis period.

[15] To convert from real to nominal escalation rate, we assume an inflation rate equal to the default O&M cost escalation rate.

[16] The annual percent increase is unique to each location and each pollutant. However, to simplify the modeling workflow and because the REopt web tool focuses mainly on grid emissions, we calculate the annual percent increase of emissions costs only for a release height of 150 meters (as opposed to calculating separate cost escalation rates for on-site fuel burn). For a given location, the annual percent increase in emissions factors for a release height of 150m differs by approximately 0.2% as compared to the percent increase for a release height of 0m.

9.3.1 Year One Emissions

Year one site emissions for each pollutant are calculated as the sum of year one emissions from utility grid purchases and on-site fuel consumption. For each emissions species, year one emissions from grid purchases are calculated as the annual sum product of the hourly marginal emissions rate [t/kWh] and grid purchases [kWh]. The user can select to consider grid emissions offset by exported electricity in the emissions calculations (the default behavior), or to exclude these exports. Emissions inventories and reporting protocols such as the Greenhouse Gas Protocol do not allow users to count exported renewable electricity as an emissions offset, but academic users may want to include these since realistically these exports are displacing grid generation and the associated emissions.

Year one emissions of each species from on-site fuel burn are calculated as the annual sum of emissions from each fuel-burning technology, based on the technology's fuel emissions rate [t/MMBTU] and the quantity of fuel burned [MMBTU].

Year one emissions savings for each pollutant are calculated as the difference between total year one emissions in the BAU and optimized case.

9.3.2 Emissions and Costs over Analysis Period

9.3.2.1 Emissions over Analysis Period

Emissions impacts for each pollutant over the financial life of the project are calculated as the sum of grid and fuel emissions. Total emissions from fuel burn are simply year one emissions multiplied by the number of years in the analysis period. Total emissions from grid-purchased electricity are calculated as year one emissions multiplied by a present worth factor, which accounts for the projected annual percent decrease in grid emissions for each pollutant. A present worth factor is needed for grid emissions, but not fuel burn emissions, because grid emissions are expected to decrease over time, whereas fuel emissions from on-site fuel burn are assumed to remain constant.

Note that the emissions calculation assumes any modeled grid outage occurs in every year of the analysis period.

9.3.2.2 Emissions Costs over Analysis Period

Total emissions costs for each pollutant is calculated as the present value of the marginal cost of each emission [$/t] times the quantity of emissions [t] over the analysis period for grid and fuel emissions. The default values for the marginal costs used in these calculations are described in the Emissions Costs section. The full formulation of this calculation can be found in Appendix C, Section 1.3.

Note that the present worth factor for grid emissions costs accounts for the projected annual percent increase in the marginal emissions cost for each species, the projected annual percent decrease in the marginal emission rate of each species, and the off-taker's discount rate. The present worth factor for fuel emissions costs mirrors the grid present worth factor, but does not assume an annual decrease in emissions factors. Climate costs over the analysis period are reported for CO_2 and health costs over the analysis period are reported as the sum of costs for

NOx, SO_2, and PM2.5. Climate and health cost savings are the difference between the total climate and health costs, respectively, in the BAU and optimized cases.

9.3.2.3 Include climate and/or health emissions costs in the objective function

In a typical analysis, climate and health cost savings over the analysis period are reported, but are *not* included in the reported net present value or life cycle cost of energy. However, under the "Renewable Energy and Emissions Accounting" accordion, users can choose to include total climate costs and/or total health costs in the objective function of the REopt web tool.

Selecting this option indicates that emissions costs will actually be in incurred by the off-taker. Therefore, if "include climate (or health) emissions in objective function" is selected, the objective function will include these emissions costs alongside all other cost considerations (e.g., capital expenses, utility bill costs) to determine the optimal system sizing and dispatch strategy. Including emissions costs will likely impact system sizes and cost-optimal dispatch strategies, as dispatchable technologies work to avoid grid purchases when emissions costs are high. Furthermore, the user should note that the project lifecycle cost and net present value will include climate and/or health costs if "include climate (and/or health) emissions in objective function" is selected.

9.4 Clean Energy Targets

Users can choose to enter either a renewable electricity target percentage (in the form of a minimum and/or maximum percentage of the site's electric load that should be served by renewable electricity) or an emissions reduction target percentage (a minimum or maximum percentage that the cost-optimal case's emissions should be reduced relative to the business-as-usual case's emissions).

Note that including renewable electricity and/or emissions reductions targets can increase solve times, as well as infeasibilities, especially when considering thermal technologies and/or battery storage.

9.4.1 Renewable Electricity Targets

Users can opt to set an annual renewable electricity target for their site in the form of a minimum and/or maximum percentage of the site's electric load that should be served by renewable electricity. REopt identifies the least-cost technology mix, sizing, and dispatch to meet this target.

If a user wants "at least" x% of their annual electric load met with renewable generation, they can set a minimum renewable electricity target of x%. Alternatively, if the user wants "exactly" x% of their annual electric load me with renewable generation, they can set the minimum and maximum renewable electricity inputs to the same value of x%.

The underlying calculations of what constitutes renewable electricity generation are described in Section 9.1. The formulation of the renewable energy target constraints can be found in Appendix C, Section 1.4.11.

9.4.2 Emissions Reductions Targets

Similar to the renewable electricity target, users can opt to set an emissions reductions target that applies to the site's CO_2 emissions, calculated as described in Section 9.2 and formulated in Appendix C, Section 1.4.11. REopt identifies the least-cost technology mix, sizing, and dispatch to meet this target.

This target is applied relative to the total (analysis period) CO_2 emissions in the BAU case. If a user assumes some future "greening of the grid" that reduces grid emissions, this greening of the grid is included in the BAU emissions calculations and is not counted towards emissions reductions calculated by REopt. Thus, REopt's emissions reduction percentage only "counts" emissions reductions facilitated by DERs.

As with the renewable electricity target, users can enter a minimum and/or maximum percentage emissions reduction target. If a user wants to reduce the site's total emissions by "at least" x% relative to the BAU emissions, they can set a minimum emissions reduction target to x%. Alternatively, if the user wants to reduce the site's total emissions by "exactly" x%, they can set the minimum and maximum emissions reduction target inputs to the same value of x%.

10 Photovoltaics

The REopt web tool uses NREL's PVWatts application to determine the electricity production of installed PV systems. The amount of electricity produced by the PV array at each time step is proportional to the hourly capacity factor at the site. Because the production of PV arrays tends to decline over their lifespan, and the model only optimizes over one year, the REopt web tool uses an average annual production profile based on an assumed 0.5% per-year degradation rate over the analysis period. We assume the inverter is replaced once during the system lifetime, and replacement cost is amortized into annual O&M costs.

The size of the PV installation is limited by available roof or land space. The default assumption allows one MW-DC of PV to be installed for every six acres of space available, and 10 DC watts per square foot of roof space. Hourly solar radiation data comes from the National Solar Radiation Database, which uses a physics-based modeling approach to provide solar radiation data for the United States in 4-km gridded segments using geostationary satellites. Data for international sites is also available for a growing number of countries as described at https://nsrdb.nrel.gov/about/international-data.html.

Refer to the PVWatts technical reference manual for further modeling assumptions and descriptions (Dobos 2014).

10.1 PV Costs

PV system costs include capital cost and O&M cost. The capital cost represents the fully burdened installed cost, including both equipment and labor. O&M includes asset cleaning, administration costs, and replacing broken components. It also includes the cost of inverter replacement. Incentives can be applied to reduce the cost; these are described in Section 4.3, Economic Incentives.

10.2 PV System Characteristics

10.2.1 PV Size

The REopt web tool identifies the system size, in kW-DC, that minimizes the life cycle cost of energy at the site. By default, there is no lower or upper limit on the size. If desired, the user can bound the range of sizes considered with a minimum and a maximum size. The minimum new PV size forces a new PV system of at least this size to appear at the site. If there is not enough land available, or if the interconnection limit will not accommodate the system size, the problem will be infeasible.

The maximum new PV size limits the new PV system (not including any existing PV system) to no greater than the specified maximum.

To remove the option of a new PV system from consideration in the analysis, set the maximum size to zero. If a specific-sized system is desired, enter that size as both the minimum size and the maximum size.

The minimum and maximum new PV size limits for technologies are assumed to be in addition to any existing PV; for example, there could be a 10-kW existing PV system, and if the user inputs a maximum new PV size of 2 kW, then the upper limit that will be allowed by the REopt web tool is 10+2 =12 kW.

10.2.2 Existing PV

If the site has an existing PV system, this can be modeled in the REopt web tool by entering its size in kW. The existing PV system will be factored into business-as-usual O&M cost calculations and net metering credits and limits. No incentives will be included for the existing PV system. If the user has chosen to optimize for energy resilience, the energy from this existing PV system will be factored into the energy resilience optimization.

When entering existing PV, the user selects how the typical energy load profile will be characterized with the addition of the existing PV system load. The default selection is Net load profile, which is the gross load minus the existing PV generation. The other option is to consider the typical energy load profile that has been entered as the gross load.

10.2.3 Module Type

The module type describes the PV modules in the array. If you do not have information about the modules in the system, use the default Standard module type. Otherwise, you can use the nominal module efficiency, cell material, and temperature coefficient from the module data sheet to choose the module type.

Table 7. Module Types

Type	Approximate Efficiency	Module Cover	Temperature Coefficient of Power
Standard (crystalline silicon)	15%	Glass	-0.47 %/°C
Premium (crystalline silicon)	19%	Anti-reflective	-0.35 %/°C

Thin Film	10%	Glass	-0.20 %/°C

PVWatts uses a basic set of equations to represent the module's physical properties and performance. The module type determines how PVWatts calculates the angle-of-incidence correction factor as sunlight passes through the module cover to the photovoltaic cell, and the cell's operating temperature. See the PVWatts Technical Reference for details (Dobos 2014).

10.2.3.1 Array Type

The array type describes whether the PV modules in the array are fixed or whether they move to track the movement of the sun across the sky with one or two axes of rotation. Options include Rooftop, Fixed; Ground Mount, Fixed (open rack); and Ground Mount, 1-Axis Tracking. The default value is a rooftop, fixed system. If 0 is entered in the roofspace available input field, the default changes to ground mount, fixed.

For systems with fixed arrays, you can choose between an open rack or a roof mount option. The open rack option is appropriate for ground-mounted systems. It assumes that air flows freely around the array, helping to cool the modules and reduce cell operating temperatures. (The array's output increases as the cell temperature decreases at a given incident solar irradiance.) The roof mount option is typical of residential installations where modules are attached to the roof surface with standoffs that provide limited air flow between the module back and roof surface (typically between two and six inches).

For the open rack option, PVWatts assumes an installed nominal operating temperature of 45 degrees Celsius. For roof mount systems, the installed nominal operating temperature is 50°C, which corresponds roughly to a three- or four-inch standoff height. See the Technical Reference for details (Dobos 2014).

10.2.3.2 Array Azimuth

For a fixed array, the azimuth angle is the angle clockwise from true north describing the direction that the array faces. An azimuth angle of 180° is for a south-facing array, and an azimuth angle of zero degrees is for a north-facing array. For an array with one-axis tracking, the azimuth angle is the angle clockwise from true north of the axis of rotation.

The default value is an azimuth angle of 180° (south-facing) for locations in the northern hemisphere. This value typically maximizes electricity production over the year, although local weather patterns may cause the optimal azimuth angle to be slightly more or less than the default values. For the northern hemisphere, increasing the azimuth angle favors afternoon energy production, and decreasing the azimuth angle favors morning energy production.

Table 8. Azimuth Angles for Different Compass Headings

Heading	Azimuth Angle
N	0°
NE	45°
E	90°
SE	135°

S	180°
SW	225°
W	270°
NW	315°

The maximum number entered must be less than or equal to 360—an error will display if a higher value is entered.

10.2.3.3 Array Tilt

The tilt angle is the angle from horizontal of the PV modules in the array. For a fixed array, the tilt angle is the angle from horizontal of the array where 0° = horizontal, and 90° = vertical. For arrays with one-axis tracking, the tilt angle is the angle from horizontal of the tracking axis.

By default, the REopt web tool sets the tilt angle to 10 degrees for a rooftop system, equal to the site's latitude for a ground mount fixed system, and to 0 degrees for a one axis tracking system. Setting the tilt equal to the latitude does not necessarily maximize the net annual output of the system, as lower tilt angles favor peak production in the summer months and higher tilt angles favor lower irradiance conditions in the winter months. Designers often use a lower tilt angle to minimize the cost of racking and mounting hardware, or to minimize the risk of wind damage to the array.

In general, using a tilt angle greater than the location's latitude favors energy production in the winter and using a tilt angle less than the location's latitude favors energy production in the summer.

For a PV array on a building's roof, you may want to choose a tilt angle equal to the roof pitch. Use Table 9 to convert roof pitch in ratio of rise (vertical) over run (horizontal) to tilt angle.

Table 9. PV Array Tilt Angle for Different Roof Pitches

Roof Pitch (Rise/Run)	Tilt Angle
4/12	18.4°
5/12	22.6°
6/12	26.6°
7/12	30.3°
8/12	33.7°
9/12	36.9°
10/12	39.8°
11/12	42.5°
12/12	45°

The maximum number entered must be less than or equal to 90—an error will display if a higher value is entered.

10.2.3.4 Direct Current to Alternating Current Size Ratio

The direct current (DC) to alternating current (AC) size ratio is the ratio of the inverter's AC rated size to the array's DC rated size. Increasing the ratio increases the system's output over the year, but also increases the array's cost. The default value is 1.20, which means that a 4-kW system size would be for an array with a 4 DC kW nameplate size at standard test conditions and an inverter with a 4 DC kW/1.2 = 3.33 AC kW nameplate size.

For a system with a high DC to AC size ratio, during times when the array's DC power output exceeds the inverter's rated DC input size, the inverter limits the array's power output by increasing the DC operating voltage, which moves the array's operating point down its current-voltage curve. PVWatts models this effect by limiting the inverter's power output to its rated AC size.

The default value of 1.20 is reasonable for most systems. A typical range is 1.10 to 1.25, although some large-scale systems have ratios of as high as 1.50. The optimal value depends on the system's location, array orientation, and module cost. The maximum number entered must be less than or equal to 2—an error will display if a higher value is entered.

10.2.3.5 System Losses

The system losses account for performance losses you would expect in a real system that are not explicitly calculated by the PVWatts model equations. The default value for the system losses of 14% is based on the categories in the table below, and calculated as follows:

$$100\% * (1 - (1 - 0.02) * (1 - 0.03) * (1 - 0.02) * (1 - 0.02) * (1 - 0.005) * (1 - 0.015) * (1 - 0.01) * (1 - 0.03)) = 14\%$$

The inverter's DC-to-AC conversion efficiency is a separate, non-adjustable input with a value of 96%. Do not include inverter conversion losses in the system loss percentage. PVWatts calculates temperature-related losses as a function of the cell temperature, so you should not include a temperature loss factor in the system loss percentage. See the PVWatts Technical Reference for details (Dobos 2014).

Table 10. Default Values for the System Loss Categories

Category	Default Value (%)
Soiling	2
Shading	3
Snow	0
Mismatch	2
Wiring	2
Connections	0.5
Light-Induced Degradation	1.5
Nameplate Rating	1
Age	0
Availability	3

The maximum number entered must be less than or equal to 99—an error will display if a higher value is entered.

10.2.4 Custom PV Generation Profile

By default, the PV production values for new PV modeled, as well as any existing PV system that is included in the evaluation, are sourced from PVWatts®. Custom PV production factors can be used in place of these profiles by uploading a user-defined PV generation profile. The file must be normalized to units of kW-AC/kW-DC nameplate, representing the AC power (kW) output per 1 kW-DC of system capacity in each time step. The file must be one year (January through December) of hourly, 30-minute, or 15-minute PV generation data.

10.2.5 PV Station Search Radius

The PV station search radius input allows the user to constrain the solar resource data sites that PVWatts will consider to those within a specified radius from the analysis site. Within the continental US, HI and parts of AK, if you choose a PV Stations Search Radius that does not include any data stations in the NSRDB dataset, then the evaluation will be stopped immediately and you will get a message that you need to increase the radius. If your site is outside these US locations, then the radius will be doubled and the evaluation will be stopped if there are no data stations in the international dataset within that doubled search radius.

In addition to this optional search radius input, the REopt web tool gives the user a warning message if the closest solar data site in PVWatts is outside of a default search radius of 100 miles in the continental US or 200 miles for international sites. If there is not a solar resource data location within this radius, this warning message will ask for your acknowledgement before you can view your results. You can search for an alternative site location that is closer to NREL's NSRDB or international datasets, at NSRDB Data Viewer and documented at the NSRD.

11 Battery Storage

Battery energy storage is modeled as a "reservoir" in the REopt web tool so that energy produced during one time step can be consumed during another. The REopt web tool does not explicitly model battery chemistries, but rather includes parameters for cost, efficiency, and SOC that can be adjusted to reflect different chemistries. The default values are representative of lithium-ion batteries. The model selects and sizes both the capacity of the battery in kWh and the power delivery in kW-AC. The battery power (kW-AC) and capacity (kWh) are independently optimized for economic performance (and resiliency, if resiliency requirements are specified)—a power-to-energy ratio is not predefined. By default, any technology can charge the energy storage device, but charging can also be limited to specific technologies.

Energy storage technologies are modeled to capture revenue from multiple value streams: performing energy arbitrage, time-shifting excess renewable energy production, and reducing demand charges or "peak shaving." The user can define the battery energy storage model characteristics including minimum SOC, initial SOC, efficiencies, minimum size, maximum size, capital cost, and replacement cost. The user can also decide whether or not the grid can be used to charge the battery. Battery cycling degradation is not included in the model; rather, we assume the battery will be replaced once during the analysis period (in year ten by default) based on calendar degradation, and include amortized replacement costs in the model. These inputs are described in more detail below.

11.1 Battery Cost

11.1.1 Capital Cost

Battery cost is defined by two parameters: energy capacity cost ($/kWh) and power capacity cost ($/kW). These costs are additive.

Energy capacity cost is the cost of the energy components of the battery system (e.g., battery pack). Power capacity cost is the cost of the power components and interconnection of the battery system (e.g., inverter and balance of system). The amount of energy that a battery can store is determined by its capacity (kWh) while the rate at which it charges or discharges is determined by its power rating (kW). While PV system cost is typically estimated based on power rating (kW) alone, battery costs are estimated based on both capacity (kWh) and power (kW).

The power components of the system (e.g., inverter, balance of system) are captured by the power metric of $/kW and the energy components of the system (e.g., battery) are captured by the energy metric of $/kWh. This allows the capacity (kWh) and power (kW) rating of the battery to be optimized individually for maximum economic performance based on the load, rate tariff, and resiliency requirements of the site. Some systems are optimized to deliver high power capacity (kW), while others are optimized for longer discharges through more energy capacity (kWh).

For example, assume the unit cost of power components is $1,000/kW, and the unit cost of energy components is $500/kWh. Consider a battery with 5 kW of power capacity and 10 kWh of energy capacity (5 kW/10 kWh). The total cost of the battery would be:

$$(5 \text{ kW} * \$1{,}000/\text{kW}) + (10 \text{ kWh} * \$500/\text{kWh}) = \$10{,}000$$

11.1.2 Replacement Cost

Replacement costs are similarly defined by energy capacity and power capacity costs, as well as replacement year. They are the expected cost, in today's dollars, of replacing the energy components of the battery system (e.g., battery pack) and power components of the battery system (e.g., inverter, balance of systems), respectively, during the project life cycle. Replacement year is the year in which the energy or power components of the battery system are replaced during the project life cycle; the default is Year 10.

11.1.3 Allowing Grid to Charge Battery

The REopt web tool allows the user to specify whether the utility grid can be used to charge the battery. If this input is set to no, the grid cannot charge the battery. Only the renewable energy system will charge the battery. If it is set to yes, either the grid or the renewable energy system can charge the battery. The default is set to yes in order to allow evaluation of batteries that are not connected to a renewable energy system.

Whether or not the grid charges the battery impacts the owner's ability to take advantage of the federal ITC and MACRS. The 2020 federal 26% ITC is generally understood to be available to batteries charged 100% by eligible renewable energy technologies, including solar and wind, when they are installed as part of a renewable energy system. Batteries charged by a renewable energy system 75%–99% of the time are eligible for that portion of the ITC. For example, a system charged by renewable energy 80% of the time is eligible for the 26% ITC multiplied by 80%, which equals a 20.8% ITC instead of 26%. The user must calculate and input the appropriate total incentive percentage.

Without a renewable energy system installed, battery systems are eligible for the seven-year MACRS depreciation schedule—an equivalent reduction in capital cost of about 20% (assuming a 26% federal tax rate and an 8% discount rate). The same benefit applies to battery systems installed along with a renewable energy system if the battery is charged by the renewable energy system less than 75% of the time. If the battery system is charged by the renewable energy system more than 75% of the time on an annual basis, the battery should qualify for the five-year MACRS schedule, equal to about a 21% reduction in capital costs.

When claiming the ITC, the MACRS depreciation basis is reduced by half of the value of the ITC. Note new tax laws concerning battery systems are pending. Refer to the Internal Revenue Service for the latest regulations.

11.2 Battery Characteristics

11.2.1 Battery Size

The REopt web tool identifies the system size that minimizes the life cycle cost of energy at the site. By default, there is no lower or upper limit on size. If desired, the user can bound the range of sizes considered with a minimum and maximum size. The minimum energy capacity size forces a battery energy capacity of at least this size to appear at a site. The maximum energy capacity size limits the battery energy capacity to no greater than the specified maximum.

To remove a technology from consideration in the analysis, set the maximum size to zero. If a specific sized system is desired, enter that size as both the minimum size and the maximum size.

An existing battery size cannot be specified.

11.2.2 Battery Efficiency

The efficiency of the battery is defined by three components:

- Rectifier efficiency: The rectifier's nominal rated AC-to-DC conversion efficiency, defined as the rectifier's rated DC power output divided by its rated AC power output. The default value is 96%.
- Round trip efficiency: This is the ratio of the DC power put into a battery to the DC power retrieved from the same battery. The default value is 97.5%.
- Inverter efficiency: The inverter's nominal rated DC-to-AC conversion efficiency, defined as the inverter's rated AC power output divided by its rated DC power output. The default value is 96%.

The product of these three efficiencies provides the total AC-AC round trip efficiency, which is the ratio of the AC power put into a battery to the AC power retrieved from the same battery. The default value is 89.9%. Note that the round-trip efficiency only accounts for DC power in and out of the battery, while the total AC-AC round trip efficiency also accounts for the need to convert AC power to DC in order to charge the battery, and DC power to AC in order to discharge the battery.

11.2.3 Battery State of Charge

The user can enter a minimum SOC to define the lowest desired level of charge of the battery. The default is 20%.

The user can also enter the initial SOC of the battery at the beginning of the analysis period. The default is 50%.

12 Wind Turbine

The REopt web tool models wind turbines of four different sizes: residential (<20 kW), commercial (21–100 kW), midsize (101–999 kW), and large (≥1000 kW). Turbine sizes and power curves for each size class are shown below.

The REopt web tool uses the site location and the wind size class selected to access wind resource data from the Wind Integration National Dataset (WIND) Toolkit. The WIND Toolkit includes meteorological conditions and turbine power for more than 126,000 sites in the continental United States for the years 2007–2013. The REopt web tool uses 2012 data because it is close to the WIND Toolkit overall average wind generation across 2007–2013.

The WIND Toolkit provides wind speed, air pressure, air temperature, and wind direction at an hourly resolution. These values returned by the WIND Toolkit are processed by the System Advisor Model (SAM) to produce the wind energy production curves used for the optimization.[17] Refer to the WIND Toolkit technical reference manual for further modeling assumptions and descriptions (Draxl et al 2015).

Wind projects exceeding 1.5 MW are constrained by land availability when this information is provided, assuming a power density of 30 acres per MW.

12.1 Wind Cost

Wind turbine costs include capital cost and O&M cost. The capital cost represents the fully burdened cost of installed wind system in dollars per kilowatt. The chart below gives the default system capital costs that are used by the REopt web tool for each wind size class. If a custom cost is entered, it will be used instead of the default cost.

Table 11. Wind Capital Cost Default Values

Size Class	System Size (kW-AC)	Base Cost ($/kW)	O&M Cost ($/kW-year)
Residential	2.5	$11,950	40

[17] https://sam.nrel.gov/

Commercial	100	$7,390	40
Midsize	250	$4,440	40
Large	2,000	$3,450	40

The O&M cost includes asset cleaning, administration costs, and replacing broken components. Incentives can be applied to reduce the cost; these are described in 4.3, Economic Incentives.

12.2 Wind characteristics

12.2.1 Size Class

The wind size class selected will determine the potential wind energy production for the site location. The size class should be selected based on site load and wind resource. The size class label refers only to the turbine size, as determined by the rated capacity (or system size), and not the end-use sector. For example, residential sized turbines are often used in commercial applications. The REopt web tool models wind turbines of four different sizes:

- Large (>=1000 kW-AC)
- Midsize (101–999 kW-AC)
- Commercial (21–100 kW-AC)
- Residential (0–20 kW-AC).

Table 12 provides the representative turbine sizes used by the REopt web tool for each wind size class. For the optimization, a single turbine installation is generally assumed.

Table 12. Wind Size Class Representative Sizes

Size Class	System Size (kW-AC)	Hub Height (m)	Rotor Radius (m)
Residential	2.5	20	1.85
Commercial	100	40	13.8
Midsize	250	50	21.9
Large	2,000	80	55

Source: Lantz et al. (2016)

The representative power curves are based on Lantz et al. (2016) but assume near-future turbine technology advancements.

Table 13. Representative Power Curves

	Residential (2.5kW)	Commercial (100kW)	Midsize (250kW)	Large (2000kW)
Wind Speed (m/s)	**kW**	**kW**	**kW**	**kW**
2	0	0	0	0
3	0.070542773	3.50595	8.764875	70.119
4	0.1672125	8.3104	20.776	166.208
5	0.326586914	16.23125	40.578125	324.625
6	0.564342188	28.0476	70.119	560.952
7	0.896154492	44.53855	111.346375	890.771
8	1.3377	66.4832	166.208	1329.664
9	1.904654883	94.66065	236.651625	1893.213
10	2.5	100	250	2000

Source: Lantz et al. (2016)

If no wind size class is selected, the default wind class value of 'commercial' will be used.

The selection of a size class does not limit the minimum and maximum sizes considered in the optimization to that range; the optimization may recommend a wind capacity that is outside of the range of sizes defined by the selected size class. In this case, the production and cost data used in the model may not apply to the system size recommended. For example, if the user selects the large size class (>1000 kW) but gets a recommendation for a 50-kW wind turbine, the recommended 50-kW turbine was incorrectly costed at the cheaper large-class cost and its production estimate used the superior wind resource of a taller large-class turbine.

If the results recommend a wind turbine in a different size class than that selected, the results will be flagged and the user can iterate on the analysis inputs, updating the size class and rerunning the optimization.

12.2.2 Wind Size

The REopt web tool identifies the system size that minimizes the life cycle cost of energy at the site. By default, there is no lower or upper limit on size. If desired, the user can bound the range of sizes considered with a minimum and maximum size. If there is not enough land available, or if the interconnection limit will not accommodate the system size, the problem will be infeasible.

To remove a technology from consideration in the analysis, set the maximum size to zero. If a specific sized system is desired, enter that size as both the minimum size and the maximum size.

13 Backup Diesel Generator

The REopt web tool models a reciprocating engine that consumes fuel and generates electricity. The fuel consumption is modeled using a linear fuel curve as described for the CHP generator in Section 14.2, CHP Fuel Consumption, and is limited to the fuel availability entered by the user.

In the web tool, generators only operate during grid outages and can only be modeled when the "Resilience" goal is checked or when "Grid" is unchecked. For resilience scenarios, the modeled backup generator is assumed to be able to operate at any partial loading (0%-100%) during a grid outage. For off-grid scenarios, the REopt web tool can model a minimum turndown, meaning the generator can operate at partial loading down to a given fraction of its nameplate capacity; any lower and it must shut off (see Section 19 for more details). In the REopt API, users can additionally allow the generator to operate while grid-connected at a specified minimum turndown.

13.1 Generator Costs

Generator costs include the installed cost, O&M cost, and diesel fuel cost. The capital cost represents the fully burdened installed cost, including both equipment and labor. O&M includes fixed regular O&M based on calendar intervals including testing, stored fuel maintenance, and service contracts. Variable O&M includes non-fuel O&M costs which vary with the amount of electricity produced. Variable O&M may include filters and oil changes, and other maintenance requirements based on engine run-hours.

Diesel fuel cost is input separately in units of dollars per gallon. Fuel availability represents the amount of fuel available on-site on an annual basis for new and existing generators. Fuel resupply is not modeled; the generator can no longer run after available fuel is expended.

13.2 Generator Characteristics

13.2.1 Generator Size

The REopt web tool identifies the system size in kW-AC that minimizes the life cycle cost of energy while meeting the critical load during the specified grid outage at the site (recommended sizing differs for off-grid microgrids; see Section 19 for more details). By default, there is no lower or upper limit on the size. If desired, the user can bound the range of sizes considered with a minimum and a maximum size. The minimum new generator size forces a new generator system of at least this size to appear at the site. The maximum new generator size limits the new generator system (not including any existing generator) to no greater than the specified maximum.

To remove the option of a new generator system from consideration in the analysis, set the maximum size to zero. If a specific sized system is desired, enter that size as both the minimum size and the maximum size.

The minimum and maximum new generator size limits are assumed to be in addition to any existing generator; for example, there could be a 10-kW existing generator, and if the user inputs a maximum new generator size of 2 kw; then the upper limit that will be allowed by the REopt web tool is 10+2 =12 kW.

13.2.2 Existing Diesel Generator

If the site has an existing generator, this can be modeled in the REopt web tool by entering its size in kW. The existing generator will be factored into business-as-usual O&M cost calculations the energy resilience optimization.

14 Combined Heat and Power

This section describes modeling and assumptions for the CHP prime mover and heat recovery system. If the user is considering CHP, assumptions include the following:

1. There is a central heating plant and heat distribution system that the CHP system can tie into. The REopt web tool does not size nor cost a conventional heating plant and heating distribution piping.
2. There is an existing fuel supply and the fuel is costed on a per-unit-of-consumption basis. There are no embedded cost assumptions for adding fuel supply infrastructure (pipeline, storage tanks, fuel pretreatments) or increasing the capacity of the fuel supply infrastructure.
3. The CHP system can operate parallel to the serving utility, providing some, all, or none of the electrical demand in any hour. The exception to this is during a resilience analysis when a power outage is simulated. Then, the critical electrical load identified by the user must be met by the CHP unit and any other sources considered for inclusion, without the utility.
4. The CHP system can serve some, all, or none of the heating load in any hour. There is no requirement that the CHP system serve all of the heating load.
5. If there is excess available heat from the CHP plant, that heat can be dumped to the atmosphere either through a generator exhaust bypass configuration or utilization of a heat exchanger unit.
6. The facility has space to install any selected system. Costs for construction of a building to house a new CHP system are not included beyond basic container costs that may be included in the total installed costs assumptions.
7. For a steam turbine CHP evaluation, the existing boiler is assumed to produce steam at the pressure and temperature required for the applicable steam turbine, and the expanded low pressure steam is at an appropriate pressure and temperature for the end-use process heat load.

Default performance parameters are available for three different natural gas-fueled CHP prime mover types: reciprocating engine, microturbine, and combustion turbine. Defaults are described in Section 14.8, Topping Cycle Default CHP Cost & Performance Parameters by Prime Mover Type and Size Class.

Each of these CHP systems has the same set of inputs which characterize installed system cost, O&M cost, electric production performance, heat recovery performance, and other constraints. The user may use defaults provided and shown in the user interface or adjust them to reflect details of the system performance and cost under consideration.

14.1 CHP Prime Mover Overview

The REopt web tool considers CHP system sizes in the range of 1 to 20 MW (20,000 kW). The CHP performance model is a generalized description of the relations of CHP outputs of power and heat to the input of fuel. These relations are linearized and capture fuel consumption and available recoverable heat as a function of the CHP prime mover's electric loading. Default CHP performance parameters are included within the model for the following prime movers:

1. Reciprocating engine
2. Combustion turbine
3. Microturbine
4. Fuel cell
5. Steam turbine

All prime movers are topping cycles except the steam turbine which is a bottoming cycle. For the topping cycles, fuel is consumed in the generation of electricity while excess heat from combustion (or chemical reaction in the fuel cell) can be captured to served site thermal loads.

The user can use the default parameters provided or modify them to represent the performance of a system of their own specification, selection, or design.

Figure 3 illustrates the energy flows for the topping cycle CHP units. Fuel is converted to electricity and recoverable usable heat.

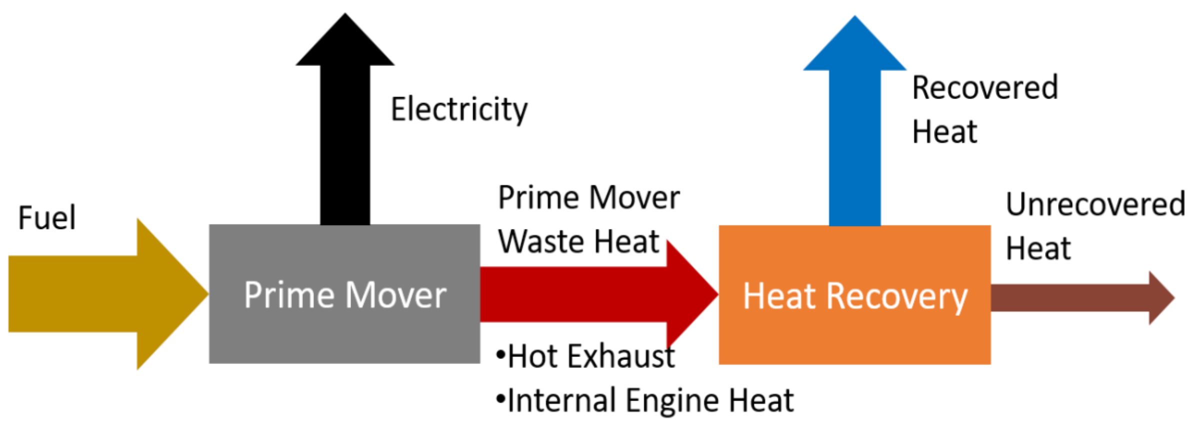


Figure 3. Topping cycle CHP diagram to illustrate the energy flows

This recovered heat can be in the form of hot water or steam. In the REopt web tool, thermal loads are assumed to be either hot water or steam. Systems that serve both hot water and steam loads are not modeled.

Figure 4 illustrates the energy flows for the bottoming cycle back pressure steam turbine CHP. Fuel is burned in the existing steam boiler to produce steam, and the steam turbine expands the steam from high pressure to a lower pressure to generate electricity. The recovered useful heat for the end-use application is extracted by condensing the low-pressure steam to a saturated liquid condition.

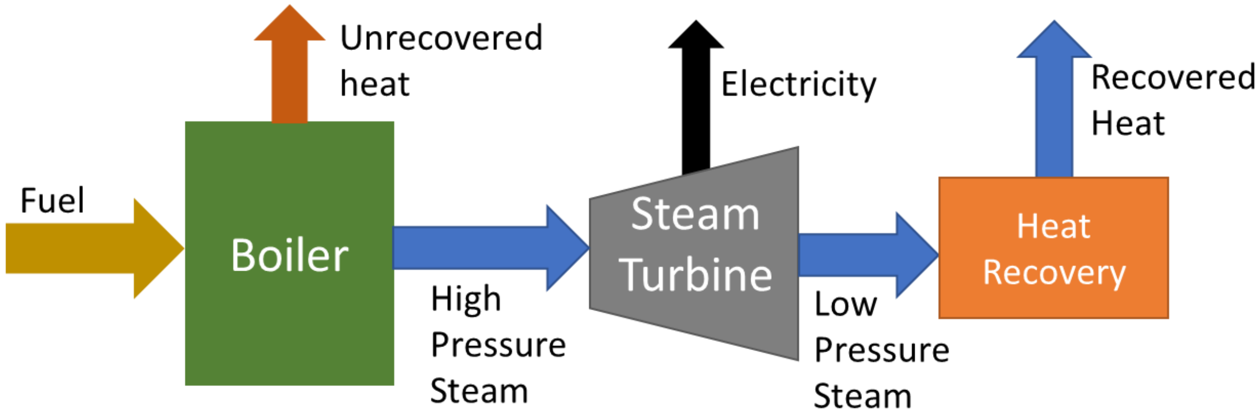


Figure 4. Bottoming cycle CHP: back pressure steam turbine

14.2 CHP Fuel Consumption

CHP fuel options include natural gas, propane, diesel, and biogas. The user-selected fuel type impacts emissions accounting.

The model for topping cycle prime movers uses a linear equation for fuel burn rate as a function of power generation. Figure 5 shows the relationship of fuel burn rate and fuel efficiency as a function of generator power output for a representative packaged CHP unit[18] selected from the DOE eCatalog for packaged CHP units (Lawrence Berkeley National Laboratory 2019).

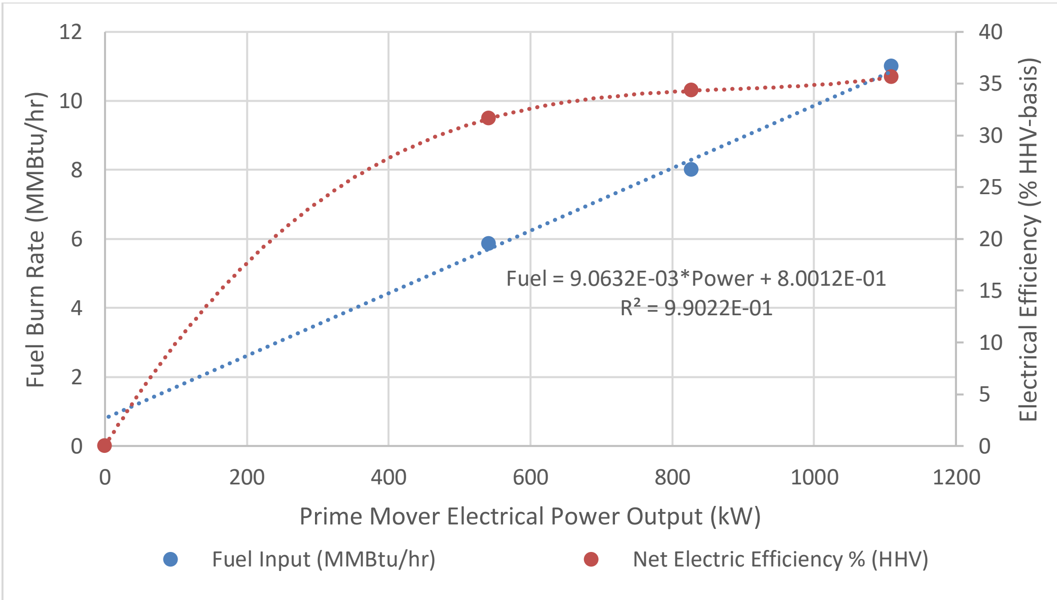


Figure 5. Modeling of CHP fuel burn rate

[18] https://chp.ecatalog.lbl.gov/package/10-SP4-ZC90001

The figure shows the electrical generation efficiency plotted on the secondary Y-axis versus load as provided. The nonlinear shape of electrical efficiency is typical, with zero efficiency at no load, poor efficiency at low load, and efficiency increasing to a maximum near or at full load. Electric efficiency is defined as:

$$\boldsymbol{Electric\ Efficiency} = \frac{\boldsymbol{power\ output}}{\boldsymbol{fuel\ consumption\ rate}} \qquad \text{Equation 2}$$

This variable efficiency is accurately modeled by use of the linear equation fit to the fuel burn rate (MMBtu/hr) versus load data also provided. As can be seen in the figure, the fuel burn rate can be accurately modeled this way (R-fit in this example is 99%). The fuel burn rate equation is:

$$\boldsymbol{Fuel\ Rate} = \boldsymbol{m_f} * \boldsymbol{Power} + \boldsymbol{b_f}\ \ [\boldsymbol{MMBtu\ fuel/hr}] \qquad \text{Equation 3}$$

The parameters m_f and b_f are calculated within the model using electrical efficiency of the prime mover at 100% load and 50% load since it is expected that these values are more readily available and less likely to be mis-entered than fuel burn rates. These efficiency points are converted to a normalized fuel burn rate (normalized based on rated electric capacity of the prime mover) to get a linear performance curve.

Electrical efficiency, and therefore the parameters *m* and *b*, will vary depending on the prime mover type and size of the prime mover with electrical efficiency generally increasing with increasing rated power.

The REopt web tool includes default values for full load and half load electrical efficiency for various prime movers. These defaults are based on DOE fact sheets, review of eCatalog packaged CHP units, and technical specifications of various commercially available units. Performance is generally reported at some standard operating conditions, typically International Organization for Standardization (ISO) reference temperature and atmospheric pressure.[19] Users should consider how performance may differ for the site specified and modify defaults as appropriate with consultation of subject matter experts.

14.3 CHP Available Heat Production

In a topping cycle, the balance of the fuel that is not converted to electricity becomes heat. In a system that generates only electricity, the heat is not useful. In a CHP system, some of this waste heat is recovered to become useful for serving facility heating loads. The level of waste heat recovery depends on both the prime mover type and design choices of the CHP system developer. In the REopt web tool the maximum available rate of heat recovery from the system is modeled similarly to fuel burn rate. Figure 6 shows the available heat from the same CHP system shown in Figure 5. The efficiency of heat recovery is shown on the secondary Y-axis and the available recoverable heat is shown on the primary axis. The equation for heat recovery efficiency is:

[19] ISO conditions are 59°F and 1 atmosphere for combustion turbines and 77°F and 1 atmosphere for reciprocating engines.

$$\textit{Heat Recovery Efficiency} = \frac{\textit{Heat available output}}{\textit{fuel consumption rate}} \quad \text{Equation 4}$$

The available useful heat is modeled as:

$$\textit{Available Useable Heat} = m_h * \textit{Power} + b_h \ [\textit{MMBtu heat/hr}] \quad \text{Equation 5}$$

The parameters m_h and b_h are calculated within the REopt web tool using heat recovery efficiency at 100% load and 50% load. These parameters are determined from CHP system specifications.

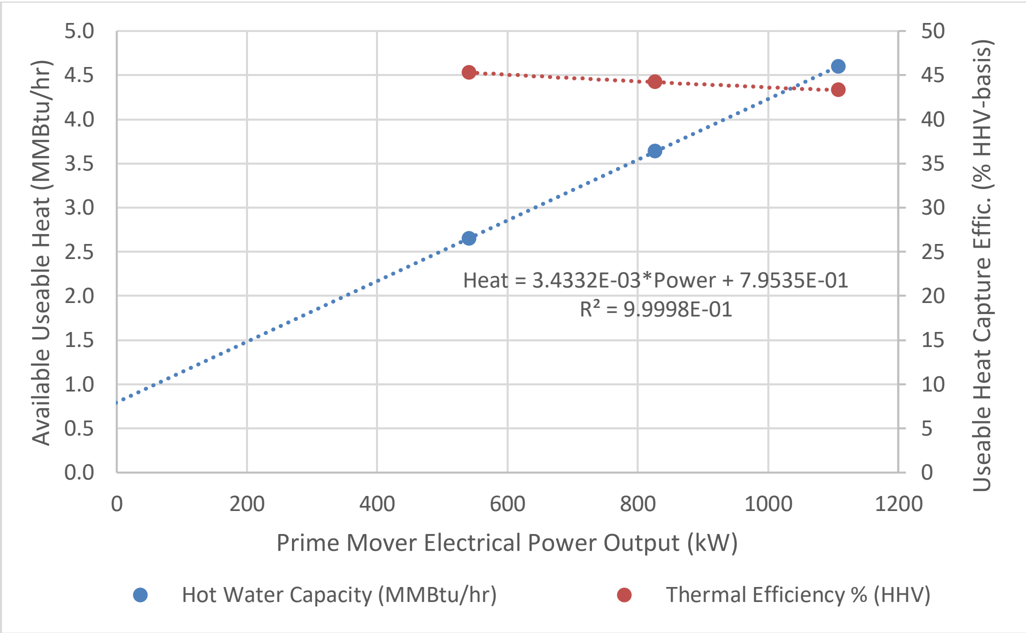


Figure 6. Modeling of CHP available useful heat

The heat recovery is described in terms of 'maximum availability' as we assume that if available heat is not needed, it can be rejected to atmosphere. That is, all, some, or none of the available heat can be used in any time step when the CHP unit is operating.

The level of heat available depends on the load, prime mover type, each vendor's heat recovery system design, and the process heat load conditions, e.g., hot water or steam. Default values for maximum available heat at full and half load are provided for the four prime mover types.

A representative heat recovery system schematic is shown for the default reciprocating engine CHP unit in Figure 7. Figure 8 shows the assumed heat recovery configuration for a microturbine and Figure 9 shows a combustion turbine. Heat recovery configuration for a combustion turbine is similar to that shown for the microturbine although the default performance parameters included in the REopt web tool for the combustion turbine are based on a unit without a recuperator.

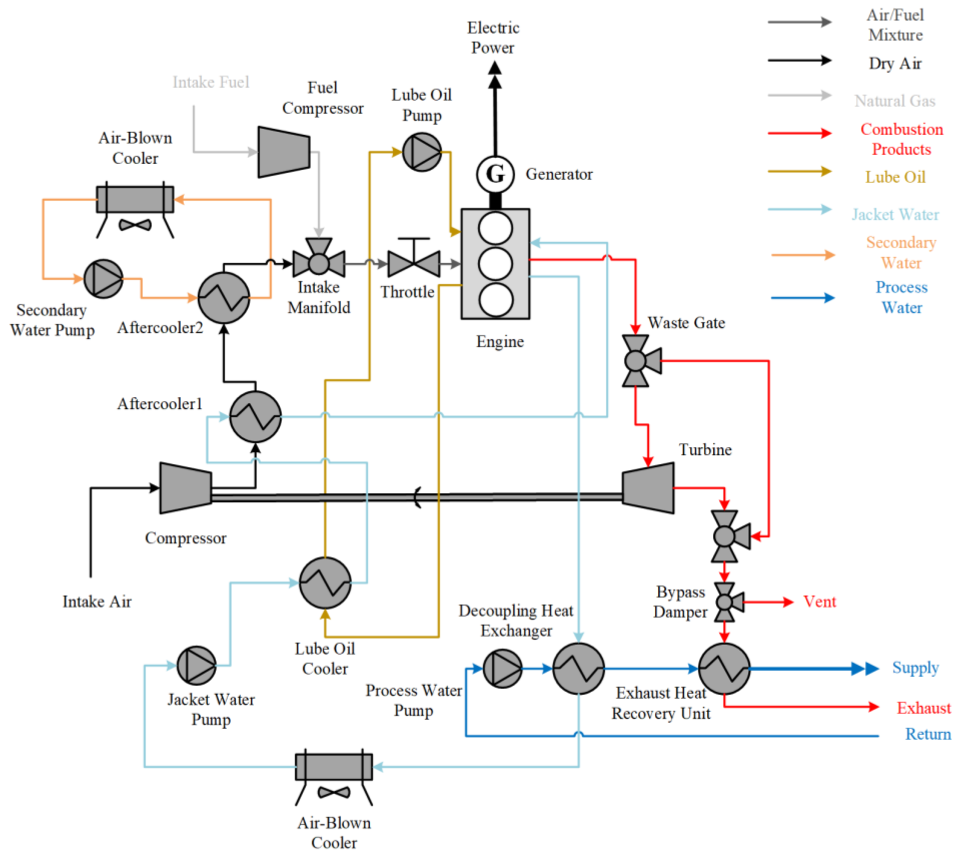


Figure 7. Heat recovery configuration for reciprocating engine CHP

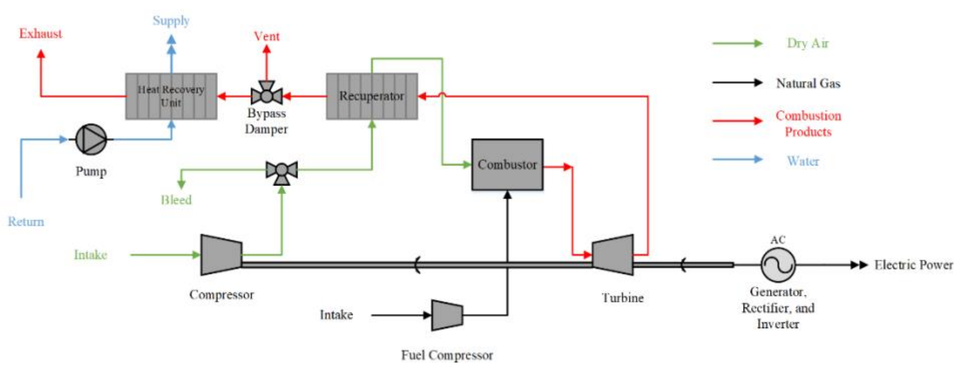


Figure 8. Heat recovery configuration for microturbine CHP

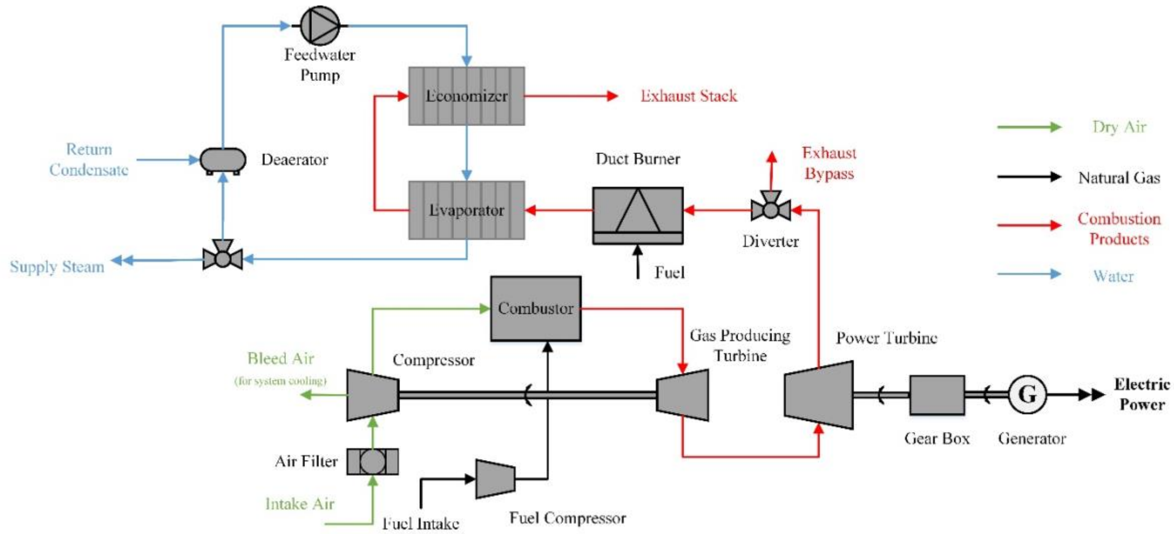


Figure 9. Heat recovery configuration for combustion turbine CHP

Default performance and costs are included in Section 14.8 Topping Cycle Default CHP Cost & Performance Parameters by Prime Mover Type & Size Class.

As previously described, performance data is generally provided by CHP equipment providers at some specific conditions, e.g., standard ISO conditions. Additionally, vendor-reported heat recovery values are based on some specific process heat conditions, e.g., some fixed water temperatures, water flow rates, or steam pressures.

14.4 Modeling Multiple Ganged Units

Designers will at times build a CHP system from multiple smaller prime movers that can then operate as a unit to provide greater maximum rated power and lower minimum turndown levels. In the REopt web tool, ganged prime movers are modeled as a single unit using the same approach and set of inputs described in Sections 14.2 and 14.3. An example of ganging multiple generators into a packaged unit would be packaging of three 200-kW microturbines to get a CHP system with 600 kW of rated power output.

As an example, Figure 10 shows the fuel consumption and electrical efficiency of one 200-kW microturbine[20] and Figure 11 shows the fuel burn rate and electrical efficiency curves for three of the units shown in Figure 10 if operated together to provide 600 kW of power.

[20] Capstone Turbine Corporation, *Capstone C1000 Series Microturbine Systems Technical Reference* (November 2011), publication 410072 Rev B.

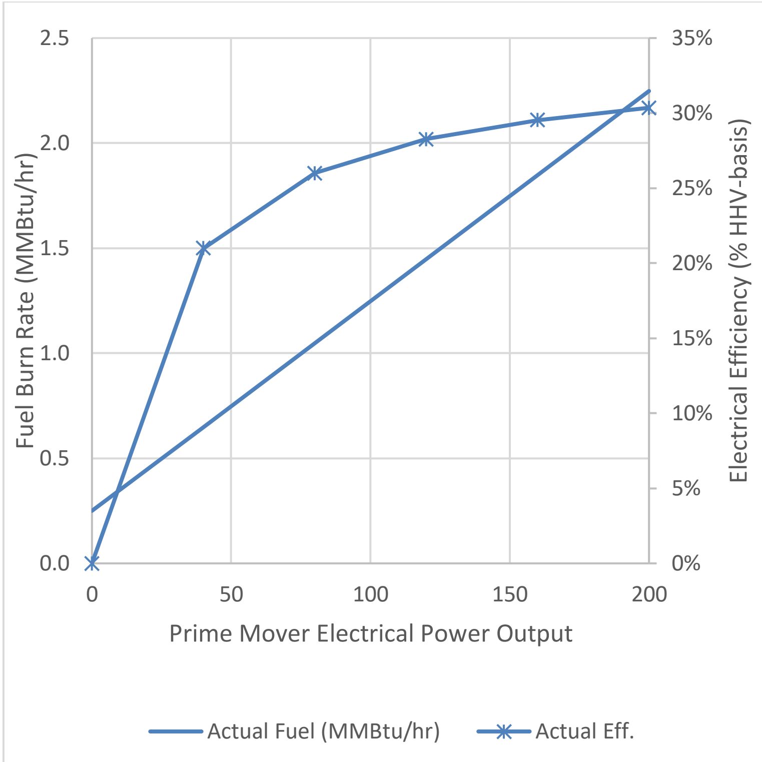


Figure 10. Fuel consumption and electrical efficiency versus load for one 200-kW microturbine

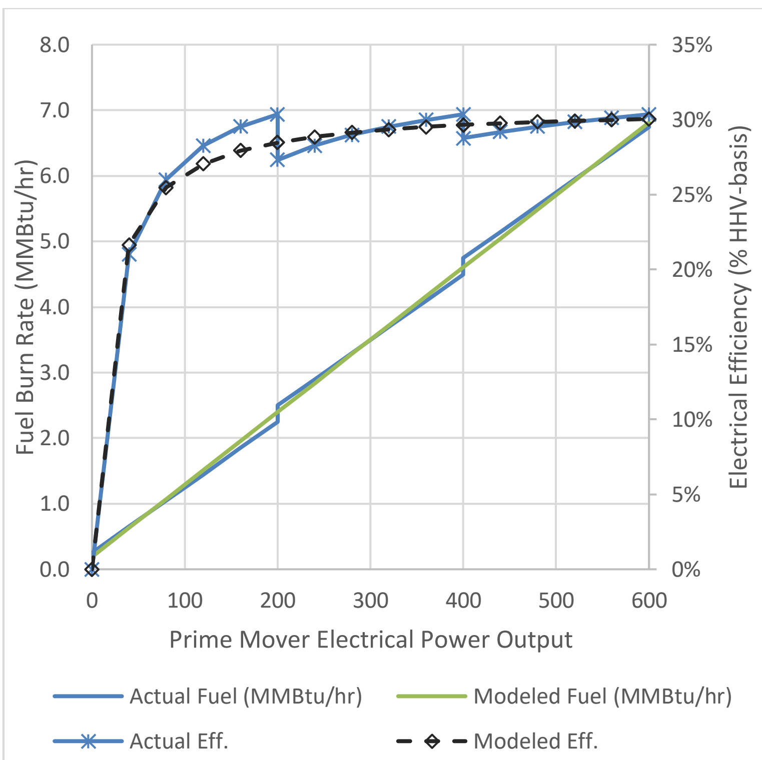


Figure 11. Actual and REopt-modeled fuel and electrical efficiency curves for three 200-kW generators packaged as one unit

In Figure 11 the discontinuous efficiency curve and fuel burn rate curve are the actual expected performance values. Each discontinuity shows how the fuel consumption changes as each 200-kW microturbine is turned on. In the REopt web tool, we simplify this behavior to allow the ganged packaged units to be modeled as one prime mover rather than, in this case, three separate generators. The continuous efficiency and fuel burn rates in Figure 11 show the simplification. In this example, the simplification introduces some error on fuel burn rates from -7% to +4% over the ganged unit's power output range. The available heat recovery parameters are similarly approximated.

14.5 Combustion Turbine Supplementary Duct Firing

It is common in combustion turbine CHP applications to add supplementary firing capability to the heat recovery steam generator (HRSG) when there is a steam load in excess of what can otherwise be produced from the hot exhaust gas. This involves installing burners near the exhaust flow inlet to the HRSG, and in operation the burners raise the temperature of the exhaust gas which allows additional steam production. Analyzing the cost-benefit of adding supplementary firing with combustion turbines can be done in REopt.

The incremental thermal efficiency for supplementary firing is very high (about 92% HHV) because the burners are adding heat to pre-heated air. The steam production with supplementary firing can be up to three times the unfired steam production. If the combustion turbine prime mover is selected, there are three inputs for supplementary firing at the bottom of the CHP section, under advanced inputs, in the CHP System Characteristics section. Table 14 shows the available input parameters and default values for supplementary duct firing of combustion turbines.

Table 14. Supplementary firing input parameters and default values

Input parameter	**Default value**
Supplementary firing maximum steam production ratio	1.0 (none), but typical is 3.0 for supplementary firing
Supplementary firing thermal efficiency (% HHV-basis)	92%
Supplementary firing capital cost[21] ($/kW)	150

In the user interface, if the user changes the 'Supplementary firing maximum steam production ratio' to a value greater than the 1.0 default, the REopt web tool will consider whether the incremental cost for the supplementary firing is worth the investment in the optimization.

[21] This is a placeholder cost. The REopt web tool team does not have a citable reference for the incremental cost of supplementary firing of a heat recovery steam generator.

14.6 CHP Auxiliary and Parasitic Loads

Parasitic and auxiliary loads include power required to run the CHP fuel pump/compressor, feedwater pumps, waste heat rejection fans, etc. For the default CHP units included in the REopt web tool, these loads are captured in the CHP net rated power output and fuel efficiency parameters. For user-entered CHP systems, the user is advised account for these auxiliary loads in the performance metrics entered.

14.7 CHP Operations Constraints

As a best practice to avoid increased O&M requirements, there are low load regimes that prime movers should not be operated within for extended periods of time. For this reason, the REopt web tool includes a user-adjustable constraint called Minimum Electric Loading of Prime Mover. The value is entered as fraction of nameplate rated power. Minimum electric load fractions for default parameters by prime mover type are described in Section 14.8, Topping Cycle Default CHP Cost & Performance Parameters by Prime Mover Type and Size Class.

As a user option, CHP generated power can export to the grid in the model.[22]

14.8 Topping Cycle Default CHP Cost & Performance Parameters by Prime Mover Type & Size Class

Default CHP performance and cost parameters are provided within the model for a number of topping cycle prime movers and size classes (size ranges) for each prime mover. The topping cycles are reciprocating engine, microturbine, combustion turbine, and fuel cell. Default costs and performance for the backpressure steam turbine (bottoming cycle) are provided in Section 14.9. Default costs and performance values assume one prime mover per CHP system. Default costs and performance parameters are shown in Table 16 through Table 19, one table for each prime mover type. The numbers in these tables are in the range of expected cost and performance based on the DOE CHP Fact Sheets (DOE Advanced Manufacturing Office 2017). The raw data used to calculate the average values for each size class are given in Appendix A. All default values are based on natural gas and are provided at near ISO rated conditions.

> **Note: Default costs and performance for natural gas CHP are not modified for other user-selected fuels. It is incumbent upon the user to review and modify costs and performance as warranted.**

The values in the tables for electrical and thermal efficiency, and the expected input for user-specified values, are based on fuel HHV.

> Note: The default values in the user interface set the electric efficiency and heating efficiency at 50% to 100% load values described in this section. The result is that the prime movers are modeled as constant efficiency units over their operating load range. This greatly simplifies the complexity of the optimization model and therefore reduces model runtimes. The user can adjust the 100% and 50% load efficiency values to model prime movers as variable efficiency units but should expect longer solve times and some

[22] In a scenario where there is no financial value for exported power, the REopt web tool may still export power to the grid in some time periods to avoid the CHP minimum loading constraint to generate and make use of the heat.

runs that may time out before a solution is found. If modeling a variable efficiency prime mover, the user is encouraged to fix the size of the generator of interest by setting the maximum size equal to the minimum size.

The total installed costs for CHP are entered as per-unit electric power capacity. The user can enter a single power-specific cost ($/kW) or enter two costs ($/kW) to generate a linear cost function. If a single input is entered, the model uses the same total installed cost ($/kW) for all CHP sizes. If both input fields are entered, total installed costs will be calculated by linear interpolation between the two cost limits. For linear interpolation, costs must be entered in ascending order (from left to right) and the total installed cost input must also have both input fields entered. CHP sizes less than the smaller size will have the first cost ($/kW), and CHP sizes larger than the larger size will have the second cost ($/kW). This linear interpolation of costs is not available for the other technology options.

In the user interface, the user first selects the existing boiler thermal production type (which the CHP system will also supply)—either hot water or steam. Then the user inputs their electric and heating loads. Built-in logic uses the thermal production type and the average annual heating load to determine the default CHP prime mover type—either reciprocating engine or combustion turbine—and the size class of that prime mover. Table 15 gives the threshold of average boiler fuel load over which the default prime mover switches from reciprocating engine to combustion turbine for hot water and steam. The reasoning for this logic is that reciprocating engines are more cost effective at smaller scales and similarly efficient at producing hot water compared to combustion turbines. Combustion turbines become applicable at larger scales and are more efficient at producing steam.

Table 15. Threshold of Average Boiler Fuel Load over which the Default Prime Mover Switches from Reciprocating Engine to Combustion Turbine

	Hot Water (Assumes Boiler Efficiency of 0.8)	Steam (Assumes Boiler Efficiency of 0.75)
Threshold of average boiler fuel load over which the default prime mover switches from reciprocating engine to combustion turbine	27.0 MMBtu/hr (equates to roughly 5,100 kW reciprocating engine and 3,600 kW combustion turbine)	7.0 MMBtu/hr (equates to roughly 3,700 kW reciprocating engine and 1,000 kW combustion turbine)

The user has the option override this default prime mover logic by clicking the “Change default prime mover & size class?” checkbox. In this case, the user has full control of the prime mover, and they must also select the size class that they want to consider.

It is the user’s option to constrain the search space for CHP size. For the example above, the user could enter the ‘Minimum non-zero power capacity (kW)’ as 100 kW and the ‘Maximum electric power capacity (kW)’ as 600 kW. In this case, the REopt web tool would run the optimization with default costs and performance representative of this range and the model would return a size within this 100-to-600-kW range, if cost effective, or a 0-kW size if CHP in this size range is not cost effective. Alternatively, the user could select to model a CHP system with costs and performance for a generator in the range of 100 to 600 kW but can expand the search space of the model to allow it to consider system sizes that are either above or below this range to see if cost-optimal sizing might indicate sizes outside the selected range might be cost effective. In the REopt web tool, the defaults for the minimum and maximum sizes for the search space are greater than the size class size ranges as shown in the tables.

As seen in Table 16 through Table 19, the default minimum size is 0 kW for all prime movers and size classes, meaning “no CHP” is always a possible result based on the optimization to minimize life cycle cost. The default ‘Minimum non-zero power capacity (kW)’ is 50% of the lower bound of the size class; however, if the result is a CHP size less than the lower bound of the size class, it is advised to rerun the model with the next-lowest size class. The default ‘Maximum electric power capacity (kW)’ is set to a high value for all size classes, although it is also advised to increase the size class appropriately if the result is higher than the upper bound of the chosen size class.

The user can enter a single power-specific cost ($/kW) or enter two costs ($/kW) to generate a linear cost function. If a single input is entered, the model uses the same total installed cost ($/kW) for all CHP sizes. If two size-cost pairs are entered, total installed costs are calculated by linear interpolation between the two cost limits. Default costs are provided for two size-cost pairs as shown in Table 16 through Table 19. When two size-cost pairs are entered, CHP sizes less than the smaller size will have the first cost pair ($/kW) and sizes larger than the larger cost pair will have the second cost ($/kW).

Default heat recovery parameters assume the following process heat load conditions:

- Hot water is generated assuming 160°F inlet and 180°F outlet, (consistent with default heat loop conditions described in Section 5.2, Heating System) for reciprocating engines and microturbines.
- Steam is generated at 150 psig saturated.

Note: It is possible that the user could set up a model that is internally inconsistent/illogical. For example, a user could specify that the existing heating plant generates steam and selects a prime mover type that is appropriate only for hot water systems. The model might still run in this case but solution results would be invalid.

Table 16. Reciprocating Engine Cost and Performance Parameters Included in the REopt web tool

Size Class	Class 0	Class 1	Class 2	Class 3	Class 4	Class 5
Class size low (kW)	30	30	100	630	1,140	3,300
Class size high (kW)	9,300	100	630	1,140	3,300	10,000
Minimum electric power capacity (kW)	0	0	0	0	0	0
Minimum non-zero power capacity (kW)	15	15	50	315	570	1,650
Maximum electric power capacity (kW)	10,000	10,000	10,000	10,000	10,000	10,000
Installed cost function, installed cost ($/kW), and size pair at lower size	$3,300, 30 kW	$3,300, 30 kW	$2,900, 100 kW	$2,700, 630 kW	$2,370, 1,140 kW	$1,800, 3,300 kW
Installed cost function, installed cost ($/kW), and size pair at larger size	$1,430 9,300 kW	$2,900, 100 kW	$2,700, 630 kW	$2,370, 1,140 kW	$1,800 3,300 kW	$1,430 9,300 kW
Fixed O&M ($/kW/yr)	0	0	0	0	0	0
Variable O&M cost ($/kWh)	0.019	0.0245	0.0225	0.020	0.0175	0.0125
Electric efficiency at 100% load (HHV basis)	35.6%	29.6%	32.1%	35.8%	39.0%	41.5%
Hot water thermal efficiency at 100% load (HHV basis)	43.6%	50.3%	47.9%	43.6%	40.5%	36.8%
Steam thermal efficiency at 100% load (HHV basis)	14.8%	0.0%	18.2%	16.9%	14.4%	12.8%
Cooling thermal factor (single effect)	0.83	0.80	0.83	0.85	0.85	0.85
Min. electric loading of prime mover (% of rated electric capacity)	50%	50%	50%	50%	50%	50%

Table 17. Micro-Turbine Cost and Performance Parameters Included in the REopt web tool

Size Class	**Class 0**	**Class 1**	**Class 2**	**Class 3**	**Class 4**
Class size low (kW)	30	30	60	190	950
Class size high (kW)	1,290	60	190	950	1,290
Minimum electric power capacity (kW)	0	0	0	0	0
Minimum non-zero power capacity (kW)	21	21	42	133	665
Maximum electric power capacity (kW)	1,000	1,000	1,000	1,000	1,290
Installed cost function, installed cost ($/kW), and size pair at lower size	$3,600, 30 kW	$3,600, 30 kW	$3,220, 60 kW	$3,150, 190 kW	$2,500, 1,000 kW
Installed cost function, installed cost ($/kW), and size pair at larger size	$2,400, 1,290 kW	$3,220, 60 kW	$3,150, 190 kW	$2,500, 1,000 kW	$2,400, 1,290 kW
Fixed O&M ($/kW/yr)	0	0	0	0	0
Variable O&M cost ($/kWh)	0.017	0.026	0.021	0.012	0.012
Electric efficiency at 100% load (HHV basis)	27.1%	24.0%	26.3%	28.5%	28.8%
Hot water thermal efficiency at 100% load (HHV basis)	41.2%	47.3%	42.7%	38.2%	37.6%
Steam thermal efficiency at 100% load (HHV basis)	0.0%	0.0%	0.0%	0.0%	0.0%
Cooling thermal factor (single effect)	0.94	0.94	0.94	0.94	0.94
Min. electric loading of prime mover (% of rated electric capacity)	30%	30%	30%	30%	30%

Table 18. Combustion Turbine Cost and Performance Parameters Included in the REopt web tool

Size Class	**Class 0**	**Class 1**	**Class 2**	**Class 3**	**Class 4**	**Class 5**	**Class 6**
Class size low (kW)	950	950	1,800	3,300	5,400	7,500	14,000
Class size high (kW)	20,000	1,800	3,300	5,400	7,500	14,000	20,000
Minimum electric power capacity (kW)	0	0	0	0	0	0	0
Minimum non-zero power capacity (kW)	475	475	900	1,650	2,700	3,750	7,000
Maximum electric power capacity (kW)	20,000	20,000	20,000	20,000	20,000	20,000	20,000
Installed cost function, installed cost ($/kW), and size pair at lower size	$4,480, 950 kW	$4,480, 950 kW	$3,900, 1,800 kW	$3,320, 3,300 kW	$2,550, 5,400 kW	$2,017, 7,500 kW	$1,650, 14,000 kW
Installed cost function, installed cost ($/kW), and size pair at larger size	$1,474, 20,000 kW	$3,900, 1,800 kW	$3,300, 3,320 kW	$2,550, 5,400 kW	$2,017, 7,500 kW	$1,650, 14,000 kW	$1,474, 20,000 kW
Fixed O&M ($/kW/yr)	0	0	0	0	0	0	0
Variable O&M cost ($/kWh)	0.012	0.015	0.014	0.013	0.013	0.011	0.010
Electric efficiency at 100% load (HHV basis)	26.7%	21.8%	23.1%	25.4%	28.1%	29.6%	31.5%
Hot water thermal efficiency at 100% load (HHV basis)	46.5%	50.7%	49.8%	47.0%	46.8%	44.9%	42.5%
Steam thermal efficiency at 100% load (HHV basis)	42.2%	46.2%	45.1%	42.5%	42.6%	40.8%	38.5%
Cooling thermal factor (double effect)	0.90	0.90	0.90	0.90	0.90	0.90	0.90
Min. electric loading of prime mover (% of rated electric capacity)	50%	50%	50%	50%	50%	50%	50%

Table 19. Fuel Cell Cost and Performance Parameters Included in the REopt web tool

	Class 0	Class 1	Class 2
Class size low (kW)	440	440	1,400
Class size high (kW)	10,000	1,400	10,000
Minimum electric power capacity (kW)	0	0	0
Minimum non-zero power capacity (kW)	440	440	1400
Maximum electric power capacity (kW)	10,000	10,000	10,000
Installed cost function, installed cost ($/kW), and size pair at lower size	$5,000, 440kW	$5,000, 440kW	$4,600, 1,400kW
Installed cost function, installed cost ($/kW), and size pair at larger size	$3,680, 10,000kW	$4,600, 1,400kW	$3,680, 10,000kW
Fixed O&M ($/kW/yr)	0	0	0
Variable O&M cost ($/hr/kW-rated)	0.038	0.036	0.040
Electric efficiency at 100% load (HHV basis)	39.9%	38.6%	41.3%
Hot water thermal efficiency at 100% load (HHV basis)	23.5%	20.6%	26.5%
Steam thermal efficiency at 100% load (HHV basis)	17.2%	14.6%	19.7%
Cooling thermal factor (double effect)	0.85	0.85	0.85
Min. electric loading of prime mover (% of rated electric capacity)	30%	30%	30%

The parameter ‘Cooling thermal factor’ included in Table 16 through Table 19 is the ‘Knockdown factor for CHP-supplied thermal to Absorption Chiller’ input in the user interface. See Section 15, Absorption Chilling for more information.

14.9 Back-Pressure Steam Turbine CHP

The back-pressure steam turbine CHP is a bottoming-cycle CHP, and the operating parameters are much different than the topping-cycle CHP. The high-level system configuration diagram is illustrated in Figure 12. Condensed water at point 1 is pumped to high pressure at point 2 where it gets heated to steam at point 3. The high-pressure steam at point 3 is expanded in the steam turbine to low pressure steam at state 4, and this process generates electricity. The low pressure steam at point 4 is condensed to a saturated liquid condition by extracting heat to the process heating load.

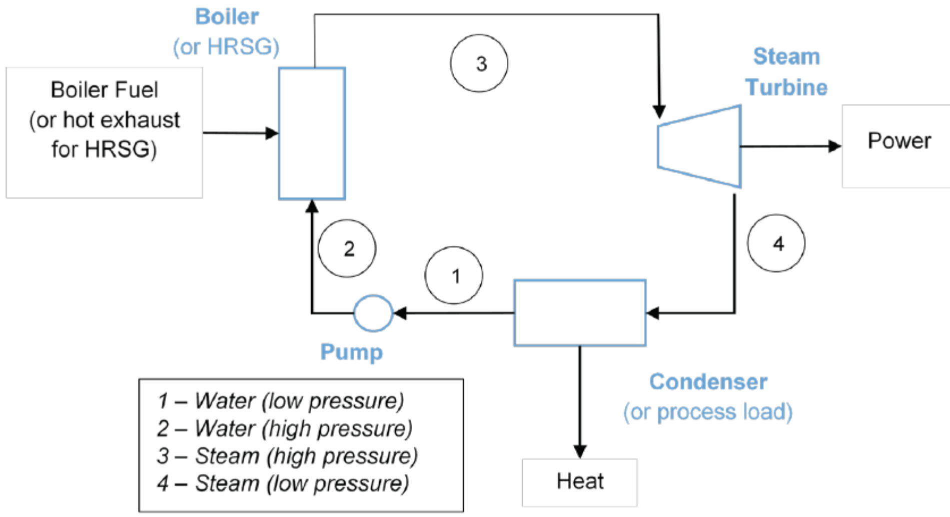


Figure 12. Back-pressure steam turbine CHP diagram (DOE CHP Fact Sheet)

When screening for backpressure steam turbine, the REopt web tool assumes an existing steam plant exists for generating steam to serve the existing process heating loads. The REopt web tool then considers whether it is cost-effective to add a backpressure steam turbine to the system for generating electricity. If added to the model, the steam turbine is assumed to be available for power generation only when heat is needed. The steam turbine can generate power in each time step using all or some of the steam going to process load. It can also choose not to generate any power. The REopt web tool assumes that if the user screens for backpressure steam turbine, the existing steam system is capable of providing the steam flow at the user-entered (or default) temperature and pressure. The REopt web tool does not consider the impact of adjusting the existing steam plant's temperatures and pressures on boiler system efficiency.

If the user selects the steam option for "Existing boiler type and assumed CHP thermal production type", steam turbine is added to the prime mover options in the CHP technology input section. The input parameters and default values for the steam turbine prime mover are listed in Table . The data for size classes 1 – 3 are based on the three steam turbine sizes listed in the DOE CHP Fact Sheets. The size class 0 data is the average data across all three size classes. The size class initially chosen by the web tool is the steam turbine size based on the average heating load of the site.

Table 20. Steam turbine default cost and performance parameters from DOE CHP Fact Sheets

Size class	**0**	**1**	**2**	**3**
Steam turbine size from Fact Sheet (kW)	Avg of ->	500	3,000	15,000
Size class range (kW)	0 – 25,000	0 – 1,000	1,000 – 5,000	5,000 – 25,000
Total installed cost ($/kW)	$828	$1,136	$682	$666
Steam turbine inlet pressure (psig)	600	500	600	700
Steam turbine inlet temperature (°F)	592	550	575	650
Steam turbine outlet pressure (psig)	117	50	150	150
Advanced inputs				
Fixed O&M Cost ($/kW/yr)	0.0	0.0	0.0	0.0
Variable O&M Cost ($/kWh)	0.008	0.010	0.009	0.006
Isentropic efficiency	63.9%	52.5%	61.2%	78.0%
Gearbox and electric generator efficiency	94.7%	94.0%	94.0%	96.0%
Net-to-gross electric power ratio	97.1%	97.4%	96.6%	97.3%

Figure 13 illustrates the steam turbine CHP performance parameters which are used to calculate the conversion efficiency of steam to net electric power. The heat recovered from the low pressure steam to the process heating load is determined by assuming the steam is condensed to a saturated liquid state and all of that energy is used (no additional heat losses).

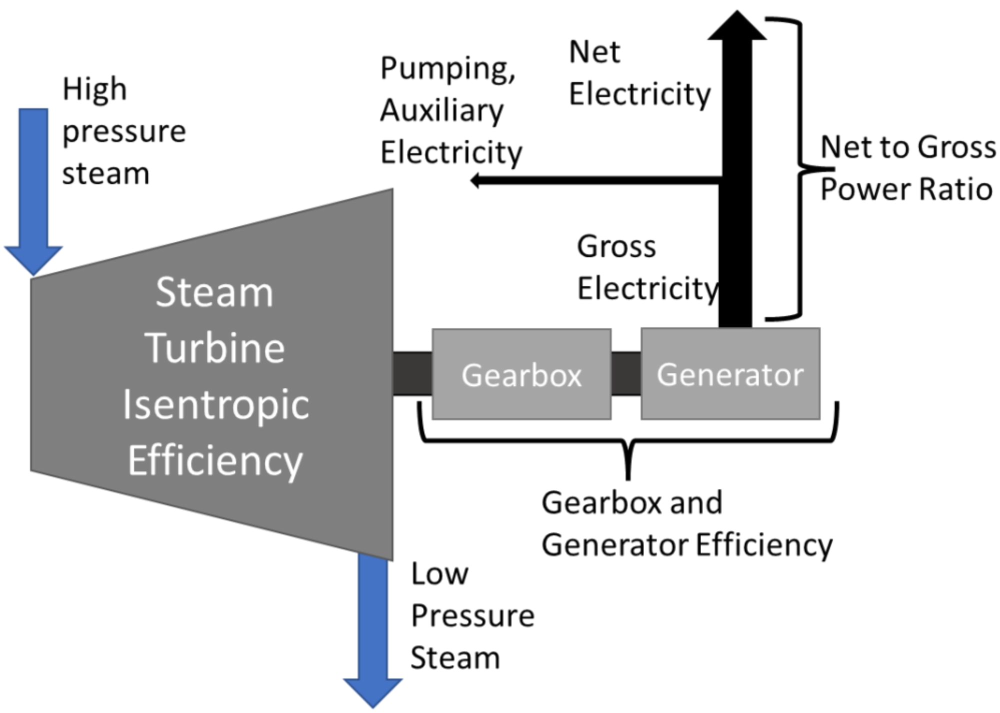


Figure 13. Steam turbine performance parameter diagram

The performance of the back pressure steam turbine is described in the following equations, and the referenced steam state point numbers are used from Figure 12.

The specific work (w_{shaft}) of the steam turbine shaft is defined by the actual enthalpy difference between the high pressure and low pressure steam which can be calculated using the isentropic (constant entropy) pressure letdown enthalpy $h_{4,s}$ and the isentropic efficiency ($\eta_{isentropic}$).

$$\boldsymbol{w_{shaft} = \left(h_3 - h_{4,s}\right) * \eta_{isentropic}\ [kJ/kg]} \quad \text{Equation 6}$$

The gross electric specific work ($w_{electric,gross}$) is calculated by the shaft power and the gearbox and generator efficiency ($\eta_{gearbox\&generator}$).

$$\boldsymbol{w_{electric,gross} = w_{shaft} * \eta_{gearbox\&generator}\ [kJ/kg]} \quad \text{Equation 7}$$

The thermal production from the steam turbine is determined by condensing the low pressure steam (state point 4) to a saturated liquid state (state point 1).

$$\boldsymbol{q_{process\ heat} = (h_4 - h_1)\ [kJ/kg]} \quad \text{Equation 8}$$

The saturated liquid (state point 1) is then pumped up to a high pressure liquid prior to entering the boiler:

$$\mathbf{w}_{pump} = \frac{(\mathbf{h}_{2,s} - \mathbf{h}_1)}{\eta_{pump,isentropic}}\ [k\mathbf{J/kg}] \quad \text{Equation 9}$$

The pumping power (w_{pump}) is not handled explicitly in the model. Instead, the pumping power is lumped into the net-to-gross electric power ($\eta_{net-to-gross-power}$) ratio which accounts for any auxiliary power requirements of the steam turbine system, including pumping and controls equipment.

$$\mathbf{w}_{\mathbf{electric,net}} = \mathbf{w}_{\mathbf{electric,gross}} * \eta_{net-to-gross-power}\ [k\mathbf{J/kg}] \quad \text{Equation 10}$$

The boiler thermal energy to heat state point 1 to state point 2 required is defined by:

$$\mathbf{q}_{\mathbf{boiler}} = (\mathbf{h}_3 - \mathbf{h}_2)\ [k\mathbf{J/kg}] \quad \text{Equation 11}$$

The model works by using ratios of:

1. Electric production to thermal consumption: $\frac{w_{electric,net}}{q_{boiler}}$
2. Thermal production to thermal consumption: $\frac{q_{process\ heat}}{q_{boiler}}$

These ratios are calculated in a preprocessing step based on the user's input steam conditions and efficiencies, and they are assumed to be constant and not a function of load. This allows the model to size and dispatch the steam turbine in REopt's mixed integer linear optimization model.

For the optimization, the maximum power available in a timestep is determined by the user's entered heating load.

Unlike the topping cycle CHP systems, there is no constraint included in the REopt web tool for minimum turndown limit for the backpressure steam turbine.

14.10 CHP Scheduled and Unscheduled Maintenance

Scheduled and unscheduled maintenance is required for CHP systems, and the REopt model accounts for this by using predetermined periods of time for which CHP is unavailable to produce electric and thermal power. Default maintenance periods are provided for reciprocating engine, microturbine, and combustion turbine prime movers based on operational data and consultation with industry experts. CHP suppliers give warranty or guarantees based on a minimum availability (hours available to operate divided by all 8,760 hours of the year); often this number is lower than the *actual* availability of the CHP system because the suppliers want to have some safety margin on their guarantees. The maintenance period defaults used in the REopt web tool represent estimates for the *actual* CHP availability. The schedule of the default periods and summary metrics can be viewed in the REopt web tool, but a high-level summary is given in Table 21.

Table 21. Default Maintenance Periods and Unavailability Summary Metrics

	Recip. Engine	Combustion Turbine	Micro-turbine	Fuel Cells
Number of planned maintenance events	6	2	2	2
Duration of planned (days)	3	2	3	3
Number of unplanned maintenance events	3	2	2	2
Duration of unplanned (days)	2	2.5	2.5	2.5
Availability	95%	97%	97%	97%

The number of planned and unplanned outages are spread out throughout the year, and in the default schedules there is no more than one in any given month. Each period is assumed to be a consecutive block of time. The planned maintenance periods are assumed to be scheduled on the weekends (which is typically off-peak if there is a time-of-use characteristic to the electric rate tariff) to the extent possible (if 2 days or less in duration). The unplanned maintenance periods are assumed to occur during the weekdays to be conservative in that the electricity rates and loads are typically the highest during the weekdays.

The user may also upload their own custom maintenance schedule with the provided form. The form is available by clicking the "Download schedule" link under the CHP Maintenance Schedule section of the CHP accordion. Table 22 provides a description of the form headings and valid inputs for those attributes.

Table 22. Custom Uploaded CHP Maintenance Schedule Form Description

	month	***start_week_ of_month***	***start_day_ of_week (1=Monday)***	***start_hour (1-24)***	***duration_hours***
Description	The month in which the outage starts	The week of the month in which the outage starts	The day of the week in which the outage starts	The hour of the day in which the outage starts	The duration of the outage, in hours
Valid range	1–12	1–6	1–7	1–24	8,760
Other notes	All values must be integers. The *start_week_of_month*=1 and *start_week_of_month*=5 or 6 often do not contain all 7 days of the week; see Figure 14 for a grid of how the *start_week_of_month* and *start_day_of_week* align with an example month (January 2017). Some months do not have a *start_week_of_month*=5 or 6. An outage must not extend past the end of the year; alternatively, specify two separate outages, one for the end and one for the beginning of the year.				

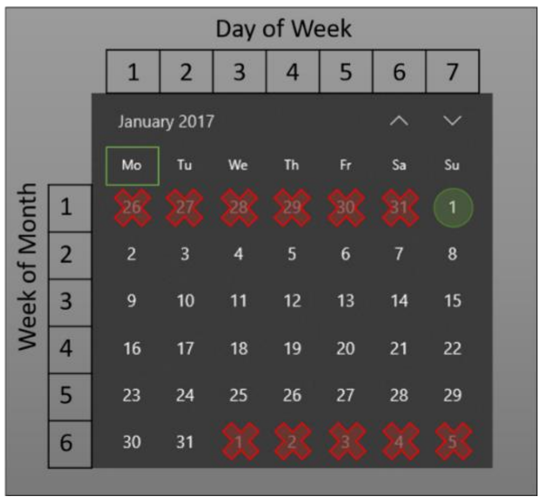


Figure 14. Example month for understanding how to build a maintenance period with respect to the year/month calendar

In the example month and year of Figure 14 (January 2017), the *start_week_of_month*=1 only has Sunday (*start_day_of_week*=6) in it, so the first valid Monday of the month would be specified by *start_week_of_month*=2 and *start_day_of_week*=1. Regarding an outage specified at the end of the month, *start_week_of_month*=6 only has Monday and Tuesday in it, so an entry of *start_week_of_month*=6 and *start_day_of_week*=3 (Wednesday) would be invalid. Note too that valid numbers for *start_hour* are 1 to 24 and that 1 represents the first hour of the day, midnight to 1 a.m. So, if the user wants to model a maintenance starting at 7 a.m., the value entered as *start_hour* would be 6.

The REopt web tool identifies the total system size that minimizes the life cycle cost of energy at the site. The minimum non-zero electric power capacity is used to narrow the lower limit of size range of the search space that the REopt web tool can select. For example, if the user enters a ‘Minimum electric power capacity (kW)’ of 0 and a ‘Maximum electric power capacity (kW)’ of 100, the REopt web tool could return a value anywhere between 0 and 100 kW. With this ‘Minimum non-zero power capacity (kW)’ input, the user could enter a value of 30 kW, for example, so that the REopt web tool can only return a system size of 0 or a size between 30 kW and 100 kW.

15 Absorption Chilling

Absorption chillers generate chilled water using a heat source to drive a refrigeration cycle. If an absorption chiller is considered, it is assumed there is an existing chilled water loop served by existing electrically driven chillers and the condenser water loop has sufficient capacity to dissipate the increased load required by the absorption chiller. The REopt web tool does not size or cost the cooling distribution system, the existing electrically driven chiller, nor size or cost incremental capacity requirements for absorption chiller condenser heat rejection.

The user can elect to consider adding an absorption chiller to supplement cooling provided by the existing electricity driven chiller plant. The heat required for the absorption chiller can be provided from CHP, the existing heating plant, and hot water TES if it is included in the model solution. The model assumes the optional absorption chiller would be connected to the process heating loop, i.e., it would add heating load to the user-entered heat load. A direct-fired absorption chiller cannot be modeled.

Absorption chiller unit heat requirements are not adjusted based on chiller loading or other operational conditions. The COP value is assumed to represent the average absorption chiller performance throughout the year. The user can adjust the default COP value. The default absorption chiller COP is dependent on whether the user selects the existing facility's boiler as producing steam or hot water. If the user selects steam, the absorption chiller is assumed to be a double-effect unit driven by steam with a COP of 1.42 kW thermal cooling output per kW thermal heat input. For a hot water boiler, we assume the absorption chiller is driven by hot water and therefore a single-effect unit with a COP of 0.74 (DOE Advanced Manufacturing Office 2017).

The parameter 'Cooling thermal factor' included in Table 16 through Table 19 in Section 14.8, Topping Cycle Default CHP Cost & Performance Parameters by Prime Mover Type & Size Class, is a 'knockdown' factor that is used to estimate the impact of absorption chillers' higher-quality heat requirements on the recoverable heat from CHP. It is the 'Knockdown factor for CHP-supplied thermal to Absorption Chiller' input in the user interface. The cooling thermal factor effectively reduces the absorption chiller COP based on two considerations: (1) the hot water-driven single effect absorption chiller requires slightly higher-temperature water than the assumed hot water loop temperatures used to estimate the default heat recovery parameters; and (2) the absorption chiller's return water temperature is not as low as the building's hot water loop return water temperature (see Section 7.4, Heating Loads). Both factors reduce the amount of CHP-produced thermal power that can be applied to the absorption chiller with its nominal COP value. For a combustion turbine prime mover supplying steam to a two-stage absorption chiller, a cooling thermal factor is also applied for a similar reason.

In addition to heat, the absorption chiller consumes electricity for heat rejection to cooling towers. The electric-based COP default is 14.1 kWt/kWe, which is equivalent to 0.25 kWe/ton. This is also a user input and can be changed.

The model does not include turn-down limits (minimum unloading ratio constraint) on the absorption chiller.

If the user selects to screen for an absorption chiller, the default cost assumption is that there is room for the absorption chiller within the existing cooling plant and that integration for parallel operation with the existing electric chillers can be accomplished. Additional costs for constructing a new building or extensive retrofits are not included. The user can change the default costs to include these.

The default capital and O&M costs for absorption chiller are dependent on the cooling capacity of the absorption chiller system. Since the web tool does not know the cost-optimal absorption chiller size before the model is run, the maximum value of the facility cooling load (units of ton) entered by the user is used as a proxy for this capacity. Table lists the data used for absorption chiller installed cost and O&M cost based on consulting from industry representatives. If the peak cooling load is below the smallest data point (10 ton) or above the largest data point (1000 ton), the smallest and largest data point costs are used, respectively. If the peak cooling load is between two adjacent data points, linear interpolation is used to calculate the costs.

Table 23. Absorption Chiller Installed Cost and O&M Cost

Peak Cooling Load (ton)	<10	50	200	300	400	500	600	700	800	900	>1000
Total Installed Costs ($/ton)											
Single Effect	7,000	3,066	2,027	1,587	1,527	1,426	1,365	1,313	1,312	1,277	1,248
Double Effect	N/A	3,723	2,461	1,960	1,855	1,709	1,623	1,547	1,520	1,470	1,427
O&M Costs ($/ton-year)											
Single Effect	300	80	36	32	31	30	28	26	23	20	18
Double Effect	N/A	100	43	36	34	32	30	28	26	23	20

16 Thermal Energy Storage

Hot water and chilled water storage tanks are insulated tanks used to store thermal energy to decouple production from consumption. We assume TES can be added to the existing systems without replacing hot water boilers or chillers. If significant system upgrades are required to add TES, the user should adjust the TES capital costs to reflect those.

The TES tank is assumed to be stratified with a thermocline that separates the supply water (hot water in hot water TES or chilled water in a chilled water TES) from the return water.

Tank capacity and costs are entered in units of gallons and $/gallon respectively. Volumetric units are converted to thermal capacity units within the model based on *temperature difference* between the supply and return water temperatures of the hot water loop (for Hot Water TES) chilled water loop (for Chilled Water TES).

Hot water from the boiler plant or the CHP heat recovery unit can be stored in a hot water TES. This hot water can then be applied to the facility hot water load or to an absorption chiller load, if considered.

Chilled water generated from the existing electric chiller and possible supplementary absorption chiller can be stored in the chilled water TES tank.

The model determines the size of TES based on the cost-optimal maximum volume of stored energy. We assume the TES can be fully charged with either hot water or chilled water. However, a minimum stored energy requirement is imposed as a fraction of total TES tank volume. This is used to represent the thermocline region which must be maintained at low stored energy levels to separate the warmer and colder sides of the thermocline. The default minimum energy storage value is 10% for both the hot and chilled water TES. The minimum SOC default is estimated from Figure 2 in ASHRAE (2016). Any minimum SOC constraint applies all year and therefore the implicit assumption is that if a tank is selected by the model, it is thermally maintained all year.

In the first hour of the simulation, stored energy is assumed to be 50% of the TES capacity. Between the maximum and minimum stored energy limits, the capacity of stored hot/chilled water is a function of the water volume stored in the tank's supply side of the thermocline.

The heat loss (or gain) depends on many factors, including the temperature of the stored fluid (and therefore the SOC of the tank), surface area to volume of the tank (which varies with TES capacity and diameter-to-height ratio), thickness of tank insulation, and ambient conditions (temperature, solar insolation, and wind speed) (ASHRAE 2016). For the REopt web tool, thermal loss is modeled as a constant rate and comes from general rules of thumb in the cited references and heat transfer calculations. The default value is 0.04% per hour (approximately 1% per day). It is intended to capture heat loss (or gain in the case of chilled water TES) of the tank to and from the environment. This time-dependent lost energy has to be met by the chiller by producing more chilled water for chilled water TES and by the boiler by producing more hot water for hot water TES when TES is included in the solution.

The maximum discharge rate from TES is not constrained as we assume in application it would be determined by the facility cooling or heating loads and therefore in the model we allow the load in any hour to be completely served by stored chilled water or hot water if the TES has sufficient stored energy.

The maximum charge rates for hot water and chilled water TES are described in the two sections that immediately follow.

Default capital costs are taken from Glazer (2019), which provides estimated total installed costs for chilled water TES over a range of sizes. Costs from the reference in units of $/ton-hour are converted to $/gallon assuming a 14°F temperature difference. The average costs range from $2.82/gallon for 100,000-gallon tank to $0.93/gallon for a 2,000,000-gallon system. These costs from the reference, converted as described, are shown in Figure 15.

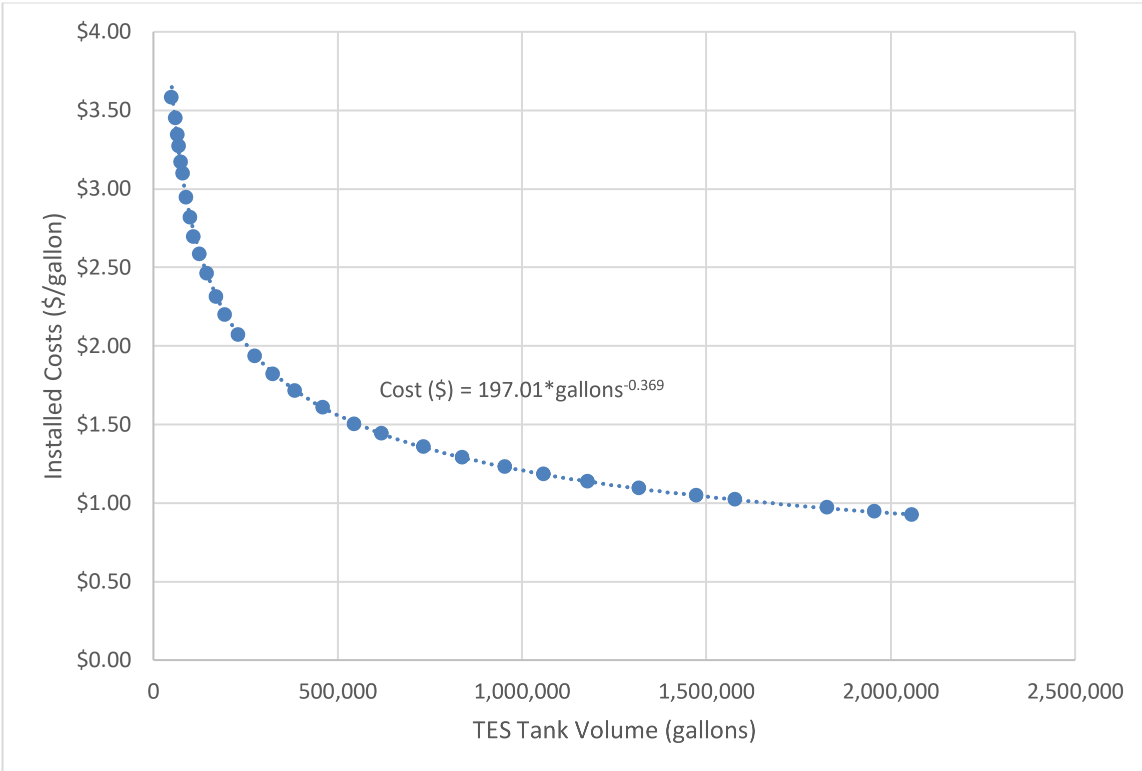


Figure 15. TES installed cost estimates from Glazer (2019) and applying a 14°F temperature differential assumption

In the REopt web tool, we set the default value to $1.50/gallon which is the cost in the reference for a tank of about 550,000 gallons. We assume hot water and chilled water TES tanks cost the same on a per-gallon basis.

O&M for the chilled water storage tank is assumed to be a fixed yearly cost, so there is no variable O&M cost component. The default cost is $0/gallon/year but the user may add this for more detailed cost assessment.

16.1 Chilled Water TES

If included, the storage system is assumed to be a single stratified water tank. The thermal storage capacity per gallon of chilled water storage is a function of the supply and return temperatures of the chilled water process loop. The default supply water temperature is 44°F and the default return water temperature is 56°F. The user may change these values to change the conversion of gallons to energy.

As described in Section 5.3, there is an assumed upper limit on the cooling capacity of the cooling plant to impose a reasonable upper limit on the maximum charging rate of chilled water TES. Therefore, the maximum charge rate is determined by the assumed size of the cooling plant. There is no constraint on discharge rate.

16.2 Hot Water TES

Hot water TES can support economics of CHP by allowing time shifting of CHP's thermal resource in situations where the electricity demand and thermal demands are not time coincident. Hot water TES is an option only for hot water process loads. If the user selects steam as the 'Existing boiler type,' the hot water TES option is disabled.

If included, the storage system is assumed to be a single stratified water tank. The thermal storage capacity per gallon of hot water storage is a function of the supply and return temperatures of the hot water process loop. The default supply water temperature is 180°F and the default return water temperature is 160°F. The user may change these values to change the conversion of gallons to energy.

As described in Section 5.2, there is an assumed upper limit on the heating capacity of the hot water heating plant to impose a reasonable upper limit on the maximum charging rate of hot water TES. Therefore, the maximum charge rate is determined by the assumed size of the heating plant. There is no constraint on discharge rate.

17 Geothermal Heat Pumps

Geothermal heat pumps can be used to provide space heating and cooling (and optionally domestic hot water (DOMHW)). This section describes the modeling and assumptions for GHP screening in the REopt web tool. In the model, a GHP retrofit for a facility is assumed to be comprised of the following major components:

1. Heat pumps
2. Geothermal heat exchanger (GHX) to act as the heat source and sink for the heat pumps
3. A building interior water loop that connects the heat pumps to the GHX.

If the user is considering GHP, the following apply:

1. The GHP system serves the entire facility space heating and space cooling as entered by the user. If using DOE commercial reference buildings (see Section 7.2 Simulated Load Profile from Models) to synthesize the heating loads, the user may choose to have the heat pumps also serve the domestic hot water heating loads. See Section 7.4 Heating Loads for how the REopt web tool handles the split of heating fuel usage between space heating and domestic hot water.
2. The GHP system is assumed to include distributed heat pumps in each HVAC zone of the facility.
3. The heat pumps units are water-to-air heat pumps (WAHP).
4. Heat pumps can operate either in heating or cooling mode as the zone requires.
5. Water piping is added to the facility to connect the ground heat exchanger to the heat pumps to serve as each heat pump's heat source and sink.
6. There is available space at the facility for geothermal heat exchanger wells.

GHP screening in the REopt web tool is fundamentally different than other REopt technology models for the following reasons:

1. Sizing: Although the size of the heat pumps is an output from the model, the size is not found through an optimization. Instead, GHP is assumed to serve the entire heating and cooling loads entered by the user. This is different than other REopt technologies where the DER are assumed to be able to operate in parallel with existing infrastructure such that it can either supplement or serve the entire set of loads if cost effective.
2. Dispatch: The heat pumps are assumed to operate at every hour to serve the heating and cooling loads as needed per the user's inputs. Therefore, heat pump operation times and levels are not a decision within the optimization.
3. Because of these two key differences from REopt DER technologies, GHP can be described as a 'Go / No-go' technology, meaning that the full system is either cost effective or not; there is no decision-making internal to the model in terms of how much of the heating and cooling loads are to be served by GHP and how the heat pumps should be operated.

17.1 Overview of the GHP Performance Model

The general approach for GHP analysis in the REopt web tool is as follows:

1. The total facility heating fuel usage and cooling loads are entered by the user.
2. An initial GHX size is chosen based on a heuristic multiplier on the coincident peak heating and cooling heat pump thermal power.
3. The hourly thermal energy being sourced from and sunk to the water loop and the hourly electricity consumption of the heat pumps is determined based on the heat pump's COP map. See 17.3 Heat Pump.
4. The net energy added into the water loop from the heat pumps is used to estimate the water loop temperature entering the GHX.
5. A separate GHX model calculates the heat transfer between the fluid loop and the ground to determine the water temperature leaving the GHX (and therefore entering the WAHPs) and the temperature of the earth in the vicinity of the GHX.
6. Steps 3 – 5 are repeated for every timestep of the simulation (typically 1-4 timesteps per hour for 25 years)
7. The minimum and maximum entering fluid temperature (EFT) of the heat pumps over the life of the system are compared to their respective limits, and a solver calculates the next iteration of GHX size to both, 1) minimize the GHX size, while 2) staying within the heat pump EFT limits.
8. Steps 3 – 7 are repeated until the solver finds the smallest GHX size which stays within the heat pump EFT limits.

GHP inputs are intended to characterize system costs, heat pump performance, and properties necessary for modeling GHX. The user may use defaults provided and shown in the user interface or adjust them to reflect details of the system performance and cost under consideration. Heat pump and GHX model and defaults are described in the following sections.

17.2 GHP Cost Model

GHP retrofit costs include capital costs and O&M costs. The capital cost represents the fully burdened installed cost, including both equipment and labor. For GHP, the total capital cost is the sum of the costs for the heat pumps, the building interior heat exchange fluid loop, and the GHX system.

The O&M cost is the incremental cost difference for GHP HVAC retrofit over the conventional HVAC system it replaces. The O&M costs do not include energy impacts of GHP retrofit as those are separately accounted for in REopt. In the REopt web tool, the *default incremental O&M cost for GHP is negative*, meaning that the O&M costs for the GHP system is assumed to be lower than the existing conventional HVAC equipment.

Default costs and references for them are provided Section 20, The REopt Web Tool Default Values, typical Ranges, and Sources. Incentives can be applied to reduce the cost; these are described in Section 4.3, Economic Incentives.

17.3 Heat Pump

The water-to-air heat pump performance model is an amalgam of commercially available vendor water-to-air heat pumps[23] based on NREL market research. Vendor units were selected that were near 5-ton capacity, the assumed nominal rating for distributed units. The performance of the heat pump is largely a function of the entering fluid temperature (EFT) from the ground loop heat exchanger. In the REopt web tool, we assume the energy requirements are solely a function of EFT, i.e., the impact of water flow rates, air flow rates, and loading on the unit are not modeled. Energy requirements as a function of EFT are entered as coefficient of performance (COP) values, where COP is a unitless parameter of thermal energy that is delivered by the heat pump divided by the electrical energy required to drive the unit.

Figure 16 shows the default heat pump COP map for the distributed WAHP as a function of EFT. The user can use the default parameters provided or modify them to represent the performance of a system of their own specification, selection, or design.

[23] Water Furnace Versatec variable speed, Trane Axiom Horizontal and Vertical Water Source Heat pumps, ClimateMaster 30 Digital Series

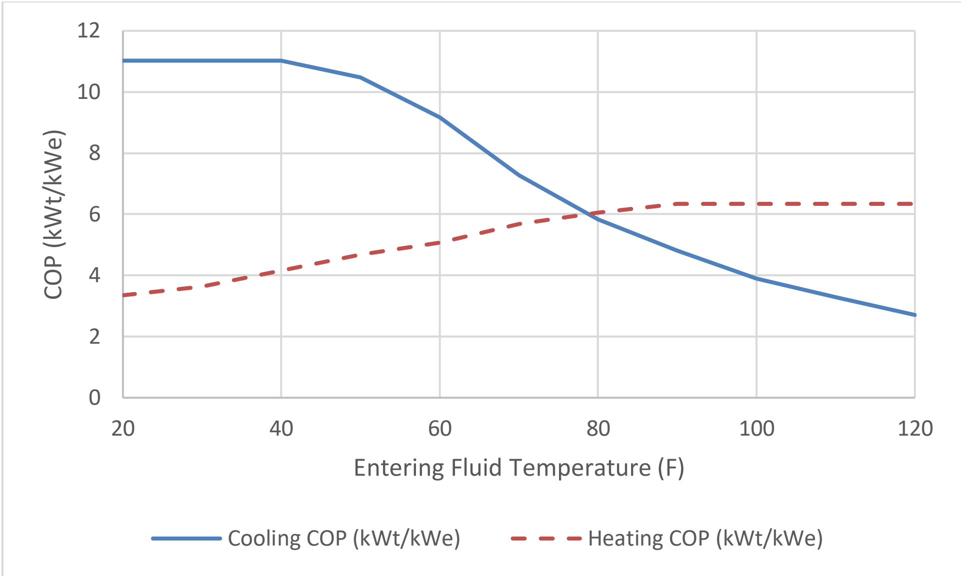


Figure 16. Default water-sourced heat pump performance map as a function of entering fluid temperature

The data points plotted in the figure above are included in Table 24. Heat pump performance is linearly interpolated for EFTs between the performance points entered while heat pump performance is assumed to be constant outside the lower and upper bounds of the EFT values.

Table 24. Default heat pump performance as a function of entering fluid temperature

EFT (°F)	Cooling COP (kWt/kWe)	Heating COP (kWt/kWe)
20	11.023	3.351
30	11.023	3.639
40	11.023	4.161
50	10.481	4.681
60	9.168	5.081
70	7.263	5.678
80	5.826	6.047
90	4.803	6.341
100	3.900	6.341
110	3.279	6.341
120	2.707	6.341

The user can use the default heat pump performance parameters or model their own. If the user uploads a custom heat pump performance map, the minimum required number of rows is one and there is no upper limit on the maximum number of rows. However, each subsequent row must have EFT greater than the EFT in the previous row. That is, heat pump performance in the table must be entered in order of increasing EFT.

Since the REopt web tool does not model each HVAC zone individually, and therefore size the heat pump for each individual zone, a ‘Heat pump capacity sizing factor’ is included as a user input that is used to increase the total capacity of the heat pumps above the maximum of the aggregated heating and cooling loads. With this factor set to 1.0, the total installed capacity of the heat pumps would be set to the maximum of the aggregated hourly heating or cooling loads. A factor above 1.0 ensures additional heat pump capacity is included based on the assumption that the heat pump capacity requirements for the individual zones will sum up to a value greater than the zone-aggregated heating and cooling loads. The default value for the 'Heat pump capacity sizing factor' is 1.1.

17.4 Geothermal Heat Exchanger

Ground-source geothermal heat pumps require a large heat exchanger in the earth to reject heat to during cooling or to extract heat from during heating. Water or a water-glycol mix is used as the heat exchange fluid and is pumped through the ground heat exchanger (GHX) and then through the building's interior heat transfer fluid loop to each heat pump.

In the REopt web tool, we assume a vertical well heat exchanger configuration. The GHX model used in the REopt tool was developed by Thermal Energy System Specialists, LLC[24] (TESS) of Madison, Wisconsin. This GHX model is proprietary to TESS, LLC and therefore is not part of the REopt tool's open-source code repository. However, a free executable file of the GHX model is available for download in a separate GitHub repository that is governed under a different license agreement than REopt. The TESS GHX model license does not allow for distribution if downloaded.

For simulation timesteps with both heating and cooling loads, the thermal energy sourced and sunk to the building interior loop from the distributed heat pumps is added together before heat exchange to the ground. That is, the heating and cooling loads from the heat pumps are netted within the water loop in each timestep to determine the entering fluid temperature to the GHX.

The following additional assumptions apply to the GHX model:

1. Vertical well configuration.
2. There is one U-tube per borehole.
3. All boreholes are connected in parallel.
4. Initial ground temperature (before GHX is added) is isothermal, undisturbed, and determined by the typical meteorological year ambient dry bulb temperatures at the start of the simulation.
5. Soil is homogeneous.

The default duration of the GHX model's simulation time horizon is 25 years, the same default as the REopt tool's economic analysis period. Depending on the relative magnitude of the heating and cooling needs, i.e., climate and facility type, the simulation years can greatly impact the size of the GHX (the number of vertical wells) and therefore the economic viability of a GHP retrofit. For unbalanced heating and cooling loads to the GHX, the size of the GHX will increase with increasing model simulation years to avoid violating the temperature limits of the heat transfer fluid. For example, in a cooling-dominated climate, the heat pumped to the GHX for space cooling is greater than the heat sourced from the GHX for space heating. Therefore, with time, the ground temperature will increase. The GHX model will iteratively increase the size of

[24] Thermal Energy System Specialists, http://www.tess-inc.com/

the GHX to find the minimum size GHX required so as not to violate the higher temperature limit for the GHX exiting fluid temperature. For a facility with relatively balanced heating and cooling loads to and from the ground, the GHX ground temperature will not drift as much with time and therefore the size of the GHX is less sensitive to the GHX simulation years parameter.

17.4.1 Inputs to the GHX model

The GHX model requires heating and cooling loads for the facility, relevant soil properties, GHX parameters, heat transfer fluid properties, heat pump performance parameters, and the hourly climate ambient temperature conditions for a typical meteorological year. Hourly ambient temperature values are determined by the site location as entered by the user. The hourly ambient temperature data comes from the PVWatts API. (See Section 10 Photovoltaics.)

A full list of GHX inputs and default parameters is shown in Table 25. The default heat exchange fluid parameters are based on water although, depending on climate, water-glycol or other anti-freeze solution may be required to protect against freezing.

Table 25. Geothermal heat exchanger system characteristics inputs

Parameter	Default	Reference
GHX simulation years	25	
Borehole (GHX well) depth (ft.)	400	1, 2
Maximum allowable GHX return water temperature (°F)	104	2
Minimum allowable GHX return water temperature (°F)	23*	2
Borehole spacing distance (ft)	20	1, 2
Borehole spacing type (dropdown)	rectangular or hexagonal	
Borehole diameter (in)	5	1
Grout thermal conductivity (Btu/hr-ft-°F)	1.0	1
GHP nominal flow rate of GHX fluid (GPM/ton)	2.5	1
GHX fluid pump power (Watt/GPM)	15	3
GHX fluid pump minimum turndown	0.1	3
GHX fluid pump power curve exponent	2.2	3
GHX pipe diameter (in)	1.66	1, 2
GHX pipe wall thickness (in)	0.16	1
GHX pipe thermal conductivity (Btu/hr-ft-deg F)	0.25	1
GHX pipe centerline distance between upwards and downwards u-tube legs (in)	2.5	4
GHX fluid density (lbm/cubic ft)	62.4	1
GHX fluid specific heat (Btu/lbm-F)	1.0	1
GHX fluid thermal conductivity (Btu/hr-ft-deg F)	0.34	5
GHX fluid dynamic viscosity (lbm/ft-hr)	2.75	5
GHX header depth (ft)	4	3
GHX simulation solver tolerance (°F)	2	3
GHX simulation solver initial guess (ft/ton)	246.1	3

*Although this is below the freezing point of water, this value is used as the default to allow the model to solve in colder climates. It is advised that the GHX fluid properties for colder climates be adjusted by the user to represent glycol-water or other anti-freeze solutions that may be applicable to prevent freezing.

References for Table 25:
(1) Kavanaugh, Steve; Rafferty, Kevin; Geothermal Heating and Cooling: Design of Ground-Source Heat Pump Systems; ASHRAE RP-1674; 2014
(2) ASHRAE, 2019 ASHRAE Handbook - HVAC Applications, Chapter 35 "Geothermal Energy"; 2019
(3) Thermal Energy System Specialists, LLC GHX model default
(4) Zheng, Z.; Wang, W.; Ji, C. A study on the thermal performance of vertical U-tube ground heat exchangers. Energy Procedia 2011, 12, 906–914.
(5) Thermal conductivity: https://www.engineeringtoolbox.com/water-liquid-gas-thermal-conductivity-temperature-pressure-d_2012.html Viscosity: https://www.engineeringtoolbox.com/water-dynamic-kinematic-viscosity-d_596.html

Default values for the ground properties are shown in Table 26 and Table 27.

Table 26. Ground properties

Parameter	Default
Ground thermal conductivity (Btu/hr-ft-°F)	Climate zone dependent. See Table
Ground density (lbm/ft³)	162.3
Ground specific heat (Btu/lbm-°F)	0.203

Table 27. Default ground thermal conductivity values by climate zone

Climate Zone	Ground thermal conductivity (Btu/hr-ft-°F)
1A	1.029
2A	1.348
2B	0.917
3A	1.243
3B	1.364
3B-Coast	1.117
3C	1.117
4A	1.023
4B	0.972
4C	1.418
5A	1.726
5B	1.177
6A	0.977
6B	0.981
7	1.271
8	1.180

Note that default data for ground thermal conductivity shown in Table 27 is highly uncertain and that this could be a key parameter that drives results. The user is advised to include a sensitivity on this parameter as well as research or perform tests to determine a more accurate value of this and other ground properties. The default ground thermal conductivity values in Table come from, Liu, Xiaobing; Joseph Warner; Mark Adams; *FY16 Q3 Milestone Report for Geothermal Vision Study Thermal Application (Geothermal Heat Pump) Complete Simulations of GHP Installations for Representative Buildings*; ORNL/LTR-2016/344; July 2016. The reference has a ground thermal conductivity of 1.034 for climate zone 7A and 1.508 for climate zone 7B. In the REopt web tool, we have only climate zone 7 (not 7A and 7B) so the default here is the average of these two values. Also, the reference does not include a value for climate zone 8. In the REopt web tool we include the average value of the of the other climate zones as the default for climate zone 8 so that the user can run the model without getting an error.

17.5 Efficiency Gain of Replacing VAV HVAC Equipment with GHP

There are inherent inefficiencies in facilities with variable-air-volume (VAV) HVAC systems that result from the need to supply air from a central air handling unit to serve the worst-case cooling need of one of the HVAC zones. As a result, facilities with VAV systems, the cooling system often generates more cooling than is required to serve the conditioned spaces and ventilation air. And the heating system often generates more heating than is required to serve the zones and ventilation air. With a GHP retrofit of a facility with VAV HVAC, elimination of the VAV system can reduce total system heating and cooling loads.

In the REopt web tool, we allow this potential reduction in heating and cooling loads to be considered. Because the REopt tool is not a building energy model, the potential heating and cooling reductions for facilities with VAV retrofits are model inputs. It is up to the user to determine whether the facility being screened includes VAV, and therefore might have a reduction in total system heating and cooling loads, and if so, how much those loads might be reduced.

To provide some estimates of potential reductions in heating and cooling loads, the REopt web tool includes default heating and cooling 'thermal efficiency factors' that users can apply in GHP retrofit analysis for facilities with VAV HVAC.

Default values were determined by performing a rigorous analysis of the DOE commercial reference building models[25]. It is important to note that these efficiency factors are based only on the models and that a careful review of assessed facility and potential thermal efficiency gains is required beyond the screening level of analysis that is possible within the REopt web tool.

Table 28 shows the default thermal efficiency factors in percentage (%) included in the REopt web tool. The factors are automatically included for analyses where the user leverages the DOE commercial reference building loads as described in Section 7 Loads. Only DOE commercial reference building models that include VAV systems have a non-unitary correction system and therefore are included in the table. For non-VAV facilities, the correction factor should be 1.0, meaning no reduction in heating and cooling system loads is expected with GHP retrofit.

[25] See Section 7.2 for additional information on the DOE commercial reference buildings and how they are leveraged in the REopt web tool.

Table 28. Default thermal correction factors in percentage (%) by climate zone and building type

Building Type	Thermal Load	1A	2A	2B	3A	3B	3C	4A	4B	4C	5A	5B	6A	6B	7A	8A
Large Office	Heating	63	33	62	65	83	49	73	94	91	97	97	98	97	98	99
	Cooling	50	50	40	46	39	34	44	38	33	38	38	38	36	36	31
Medium Office	Heating	70	55	58	81	78	46	88	92	88	97	96	98	97	98	99
	Cooling	67	63	59	59	55	43	57	56	38	49	56	49	50	46	40
Primary School	Heating	87	93	78	98	88	76	99	95	94	98	97	99	98	99	99
	Cooling	88	88	79	85	74	63	85	72	58	72	75	73	72	72	64
Secondary School	Heating	93	97	88	99	95	88	100	98	98	99	99	99	98	99	99
	Cooling	92	92	88	90	86	75	90	86	75	79	83	76	76	71	59
Hospital	Heating	76	65	66	62	72	62	67	79	82	85	84	87	88	89	93
	Cooling	74	73	68	69	68	63	69	71	70	70	73	70	74	71	73
Outpatient	Heating	99	89	83	86	87	79	71	89	88	92	92	94	94	95	97
	Cooling	84	85	77	81	77	70	69	76	73	74	77	75	76	75	73
Large Hotel	Heating	100	93	84	95	91	84	98	95	95	99	97	99	98	99	99
	Cooling	91	92	87	87	83	81	88	80	82	85	79	82	81	80	77

For more detailed discussion of the methodology and assumptions used to generate the default thermal correction factors, see Appendix B.

18 Outputs

18.1 Cases

The REopt web tool reports results for up to three cases: Business-as-Usual, Financial, and Resilience. Resilience is reported only if the user selects a resilience analysis.

- **Business-as-Usual:** In this case, the site purchases energy solely from the utility. In a scenario modeling a grid outage where the critical load can be fully met by an existing generator for some period of time, then Business-As-Usual also includes the costs of using that existing generation capacity for that time.
- **Financial:** The case that minimizes the present value of all future energy costs over the analysis period. This case may include a combination of utility, PV, wind, CHP, GHP, chilled water storage, hot water storage, absorption chiller, and/or battery. This case is not optimized for a grid outage.
- **Resilience:** This case is optimized to sustain a critical load in the event of a grid outage while minimizing the present value of all future energy costs over the analysis period. This case may include a combination of utility, PV, wind, battery, CHP, GHP, chilled water storage, hot water storage, absorption chiller, and/or backup generator.

18.2 System Size

The REopt web tool leverages a mathematical optimization model to determine the cost-optimal size and dispatch of DER including PV, wind, CHP, backup diesel generator, absorption chiller, battery, and thermal storage subject to technology costs, the site's load, cost of electricity and fuel, solar or wind resource, and other financial inputs.

A technology is typically recommended if it reduces the life cycle cost of energy for the site. In general, DER is often cost effective at sites that have a higher utility rate, higher utility escalation rate, lower DER cost, good incentives, and/or good renewable resource that make energy generated by DER less expensive than energy purchased from the utility. For CHP, the combination of high electric rate, low fuel cost, and high thermal load can make electricity generated by CHP less expensive than electricity purchased from the utility and heat generated by CHP less expensive than heat produced by the existing boiler. For batteries, high demand charges are important for economic viability. Thermal storage is often cost effective at sites where thermal energy is produced at a different time than it is needed. An absorption chiller may be cost effective at sites that have a high cooling load, high electricity costs, low fuel costs, and/or CHP.

If DER is not recommended, this is likely because utility costs, incentives, and/or renewable resources are low, and therefore DER may not be cost competitive with utility prices at this time. The cheapest option might be to continue to purchase grid electricity. On the other hand, if the model over-sizes a technology, resulting in energy curtailed or sent back to the grid at no value, this is likely because the value it gains from energy generated at other times reduces total life cycle cost of energy, even if energy is curtailed in certain hours.

If the user specified a minimum DER size or a resiliency requirement, DER may be recommended to meet these requirements even if it does not reduce the life cycle cost of energy. If the user did not select a technology for inclusion in the analysis, or set the maximum technology size to zero, the technology will not be recommended even if it is cost effective. The total system size includes an existing system if one has been specified in the inputs (for PV and diesel generator).

With the exception of GHP, the model considers a continuous range of technology sizes; it is not limited to the discrete sizes available in the marketplace. Therefore, the system sizes recommended may not be commercially available. In this case, the user may identify available sizes close to the optimal recommendation and rerun the model with fixed sizes equal to the commercially available size.

18.2.1 Energy Production

In addition to system size, the REopt web tool also reports AC energy generation from each technology, and fuel used to generate this energy (where applicable). The expected annual energy production from the PV system is the average expected production over the system lifetime (including degradation), not Year 1 production.

18.3 Dispatch Strategy

The model optimizes the dispatch strategy of each technology to meet the load at minimum life cycle cost of energy. In each time step, generation may serve the load, or be stored, curtailed, or, in the case of electricity, exported back to the grid. Storage technologies may be charged or discharged. The dispatch strategies for electric, heating, and cooling loads are provided in interactive graphs that allow the user to scroll through the year, zoom in on select days, and zoom out to see the full year. The full hourly dispatch strategy for one year can be downloaded as a .csv file.

18.3.1 Electric Dispatch

For every hour of the year, the electric dispatch chart titled System Performance Year One shows the electric load as a black line. For evaluations that include chilled water TES or an absorption chiller, a dashed black line represents the business-as-usual electric load, which was entered by the user. The total electric load, shown as the solid black line, is the net of this business-as-usual load and any cooling electric offsets or additions due to recommended absorption chiller and/or chilled water TES systems. This net total electric load is the load that must be met by some combination of technologies in every hour of the year.

The load must be met in each hour by either energy purchased from the grid, PV, wind, battery storage, CHP, or, in an outage, by an optional backup diesel generator. PV and wind generate energy according to when the resource is available and either serve the load, charge the battery, or export to the grid. CHP generates energy according to site economics and either serves the load, charges the battery, or exports to the grid. Load not met by PV and/or wind is met either by the CHP prime mover, the battery discharging, the grid, or, in an outage, by an optional backup diesel generator. During a grid outage, excess generated electricity is curtailed.

The optimization model decides whether to charge, discharge, or do nothing with the battery in each hour. If it charges or discharges, it also decides by how much. The battery SOC is shown as a dotted black line. The battery is sized and dispatched to minimize the life cycle cost of energy at the site. There is no demand target. Instead, demand levels are determined by the optimization model.

18.3.2 Heating Thermal Dispatch

A similar chart is provided for the heating thermal dispatch. The business-as-usual heating load is shown as a dotted black line. This heating load represents the typical heating boiler fuel load entered by the user. It does not include the hot water TES or absorption chiller loads which are included in the total heating load, shown with a solid black line.

The load must be met in each hour by either the existing boiler, CHP, or hot water TES serving the load. The CHP generates heat and the hot water TES stores and releases heat according to site economics. Both CHP and hot water TES either serve the load, charge the TES, or supply heat to an absorption chiller. The hot water TES state of charge in each hour is represented by a dotted red line.

Like the battery, the optimization model decides whether to charge, discharge, or do nothing with the hot TES in each hour. If it charges or discharges, it also decides by how much. The TES is sized and dispatched to minimize the life cycle cost of energy at the site.

18.3.3 Cooling Thermal Dispatch

Finally, a third chart is provided for the cooling thermal dispatch. For every hour of the year, the chart shows the total cooling load as a solid black line. This load must be met in each hour by either the electric chiller, the absorption chiller, or the chilled water TES. The absorption chiller and electric chiller either meet the load or charge the chilled water TES according to site economics. The chilled water TES state of charge in each hour is represented by a dotted red line.

The optimization model decides whether to charge, discharge, or do nothing with the chilled water TES in each hour. If it charges or discharges, it also decides by how much. The TES is sized and dispatched to minimize the life cycle cost of energy at the site. There is no demand target; demand levels are determined by the optimization model.

18.4 Economics

The REopt web tool reports economic metrics on the financial viability of each case. Metrics reported include Year 1 utility costs before tax, life cycle utility costs after tax, capital cost before and after incentives, Year 1 and life cycle O&M costs, total life cycle cost, NPV, payback period, internal rate of return, and technology-based levelized cost of energy. For third party-financed systems, annual payments from the host to the third-party owner are also reported. More detailed financials are available in the downloadable pro forma spreadsheet.

The objective of the optimization is to minimize life cycle cost (and therefore maximize NPV). The life cycle cost is the present value of costs, after taxes and incentives associated with each case. For the Business-as-Usual Case, this includes only the utility demand and energy costs, existing boiler fuel costs, and future O&M costs for any existing PV and/or generator. In a scenario where a critical load is fully met by an existing backup diesel generator, then this calculation also includes the fuel and operating cost of using that existing generation capacity to meet the outage. For the Financial or Resilience cases, this includes the utility demand and energy costs as well as the capital expenditure, tax benefits and incentives, and O&M costs associated with the project, including PV, wind, energy storage, CHP, GHP, absorption chiller, and total backup diesel generator (if recommended). Note that fixed fees charged by the utility are not always included, and therefore the actual life cycle cost of energy may be higher if the utility charges fixed fees. However, because fixed fees cannot be offset by PV, wind, energy storage, or CHP, these net out in the calculation of NPV.

The NPV is the present value of the savings (or costs if negative) realized by the project. This is calculated as the difference between the Business-As-Usual Case life cycle energy cost and the Resilience Case or Financial Case life cycle energy cost. For financial analysis, NPV will be greater than or equal to zero, unless the user has forced a minimum technology size. For a resilience analysis, the NPV may be positive or negative. A negative NPV indicates the project is not economically viable, or in other words, the site will pay more than their base case cost of electricity. Note that avoided outage costs are not considered in the NPV calculation; adding in these avoided costs may increase NPV.

While the REopt web tool reports payback period and IRR as well, the optimization does not maximize these metrics. The REopt web tool is maximizing NPV, and IRR and payback period are simply calculated for the system that maximizes NPV.

18.5 Resilience

If the user selects a resilience evaluation, the REopt web tool optimizes the system to meet the typical load at minimum life cycle cost, with the additional constraint that the load must be met without the grid during the specified outage period. The results then compare the system optimized for resilience to one optimized for financial benefit.

18.5.1 Outage Simulation

The outage simulator provides an evaluation of the amount of time a system can survive grid outages throughout the year. In the user interface, it is accessible on the results page after the optimization is run by selecting the 'Simulate outages' button.

The system was optimized to meet a specific outage period, but because load and solar and wind resource vary throughout the year, a system sized to sustain a given outage duration at one time may not be able to sustain the same outage duration occurring at a different time. Outages are simulated starting at every hour of the year (8,760 simulation runs) and the amount of time the system can sustain the critical load during each outage is calculated. Based on the simulation, the REopt web tool reports the minimum, average, and maximum time survived across the 8,760 simulated outages, as well as avoided outage costs. Data can be viewed for the entire year, or by month or hour in which the outage starts.

The battery SOC at the start of each outage is determined by the economically optimal dispatch strategy. This means that if the battery was being used for peak shaving prior to the outage, it may be at a low SOC when the outage occurs.

Note that in order to gain this resiliency, the PV/wind/CHP/battery/generator must be installed as a system capable of electrically islanding. This incurs additional costs above a typical grid-connected system that are not included in the economics presented here. Additional components required may include a manual or automatic transfer switch, critical load panel, and additional controls capabilities in the inverter for islanded operation.

18.5.2 Effect of Resilience Costs and Benefits

If the user runs the outage simulator, the REopt web tool provides an interactive chart that allows the user to consider the cumulative effect of extra costs and benefits of increased resilience on the project's NPV. Upgrading the recommended system to a microgrid allows a site to operate in both grid-connected and island mode. This incurs additional costs above a typical grid-connected system, which are not included in the economics of the primary optimization. This "microgrid upgrade cost" may include extra equipment such as controllers, distribution system infrastructure, and communications upgrades required to make the DERs an island-able system.

Economic benefit is also observed when the value of avoiding the costs of an outage is considered. Avoided outage costs are the losses that the site would experience if the load were not met. The value of lost load is used to determine the avoided outage costs by multiplying value of lost load in $/kWh by the average number of hours that the critical load can be met by the energy system (determined by simulating outages occurring at every hour of the year), and multiplying by the mean critical load. The outage event is assumed to occur every year of the analysis period and the avoided outage costs for one year are escalated and discounted to account for the annually recurring outage. This assumption does not impact the optimization results or NPV calculation for the project.

The Interruption Cost Estimate Calculator[26] can aid in estimating interruption costs and/or the benefits associated with reliability improvements.

These microgrid upgrade costs and avoided outage costs are not factored into the optimization results, but their impact can be evaluated in this chart. The sliders under the chart allow the user to change the Microgrid Upgrade Cost and the Avoided Outage Costs to analyze the impact on the NPV after Microgrid Costs and Benefits, while the NPV Before Microgrid Investment, which is determined by the optimization results, remains static.

18.6 Renewable Energy and Emissions

In the Results Comparison Table, the REopt web tool reports the percentage of annual electricity consumption provided by on-site renewable generation (from PV, wind, or renewable fuels). By default, this percentage includes any renewable electricity that is exported to the grid, but the user may change this assumption on the inputs page. If fuel-burning technologies that serve thermal loads are modeled, then the percentage of annual *energy* consumption (electric loads plus non-electrified heat (steam/hot water) loads) that is derived from on-site renewable generation is also reported.

The Results Comparison Table also reports Climate & Health Emissions summary outputs for each case, including year one emissions and the percent reduction in CO_2 emissions from the BAU scenario. By default, the emissions totals assume that exported electricity offsets grid emissions, but the user may change this assumption on the inputs page. If the user selects “include climate (and/or health) emissions in objective function” on the inputs page, then the cost of climate and/or health emissions (included in the objective) over the analysis period will appear as non-zero values under the “Life Cycle Cost Breakdown” section of the Results Comparison table. This indicates that the costs are assumed to be true costs incurred by the project in both the BAU and optimized cases. Refer to Section 9.2.1 for guidance on interpreting emissions results. In short, if entering marginal emissions factors for grid electricity, the “Difference” column appropriately captures avoided emissions using marginal emissions factors, but the BAU and Financial columns should be interpreted with caution as a site’s emissions footprint should typically be reported using average (rather than marginal) emissions factors.

[26] https://icecalculator.com/home

The Clean Energy Outputs table includes the renewable energy outputs described above along with more detailed emissions results by species (CO_2, NOx, SO_2, and PM2.5), including breakdowns between emissions from grid purchases and fuel burn. The "breakeven cost of CO_2 emissions reduction (\$/t CO_2)" is also reported for scenarios in which the project NPV is negative. This value indicates the cost of CO_2 that would bring a negative NPV to 0 (making the project "break even" with BAU costs of energy). This cost of CO_2 can be compared to the social cost of carbon and/or other emissions reduction approaches.

For more details on the methodology and data sources used for emissions and renewable energy calculations, refer to Section 9.

18.7 Caution Information

Investment decisions should not be made on the REopt web tool results alone. These results assume perfect prediction of solar irradiance, wind speed, and electrical and thermal loads. In practice, actual savings may be lower based on the ability to accurately predict solar irradiance, wind speed, and load, and the control strategies used in the system. When modeling a grid outage, the results assume perfect foresight of the impending outage, allowing the battery system to charge in the hours leading up the outage. If a natural gas-fueled CHP system is included, the resiliency results assume the natural gas supply is not disrupted during an electrical grid outage.

The results include both expected energy and demand savings. However, the hourly model does not capture intra-hour variability of the PV and wind resource. Because demand is typically determined based on the maximum 15-minute peak, the estimated savings from demand reduction may be exaggerated. The hourly simulation uses one year of load data and one year of solar and wind resource data. Actual demand charges and savings will vary from year to year as load and resource vary.

Asset dispatch decisions are determined by the model as part of the cost-minimization objective. In application, some aspects of these operational decisions may not work well with the existing infrastructure or may not follow best practices. For example, in results with CHP, boiler dispatch may result in short cycling or periodic boiler use that is not possible without hot-standby. The user should review the dispatch results with these limitations in mind.

The REopt web tool may find CHP is cost effective but upon review of its operation, the user may find that the REopt web tool operated CHP in an unconventional manner. For example, CHP systems are often operated in baseload and sized to maximize heat recovery. In the REopt web tool, CHP sizing and dispatch are determined as part of the cost-minimization objective. In some modeled scenarios, the determining value of CHP may be reduction of electric utility demand charges. The value of heat recovery and avoided utility electricity costs in off-peak hours may be insufficient to offset the operation costs of CHP and therefore the REopt web tool might not operate CHP in baseload. Examination of the results may reveal the CHP system operated at low capacity factors or that the size of the unit resulted in low utilization of the available waste heat. The user is advised to review the relevant metrics and resultant economics to identify why the model has indicated CHP might be cost effective. For low capacity factors and/or low heat utilization, the value of the CHP unit might be heavily tilted to the power generated.

PV system performance predictions calculated by PVWatts include many inherent assumptions and uncertainties and do not reflect variations between PV technologies nor site-specific characteristics except as represented by inputs. For example, PV modules with better performance are not differentiated within PVWatts from lesser-performing modules.

Wind performance predictions are approximate only. Actual wind turbine performance is greatly affected by obstacles surrounding the turbine, including trees, buildings, silos, fences, or any other objects that could block the wind flow. Looking at a wind rose for the site is the best way to estimate the impact of local terrain and obstacles on the potential turbine energy production; Figure 17 gives a rule of thumb for where not to install a wind turbine (wind from the left).

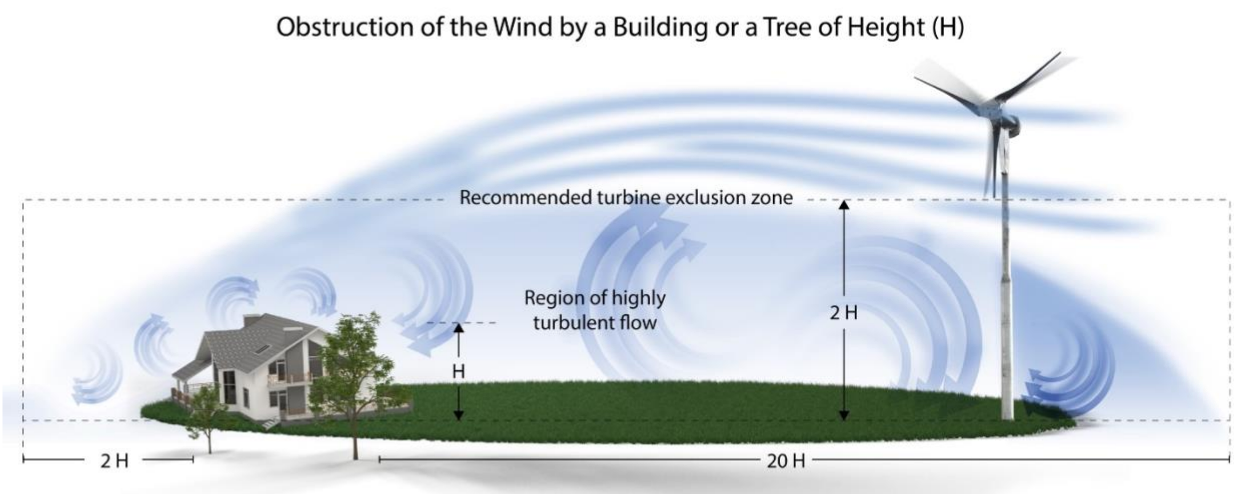


Figure 17. Obstacles to potential wind energy production

18.8 Next Steps

This model provides an **estimate** of the techno-economic feasibility of solar, wind, CHP, GHP, and battery, but investment decisions should not be made based on these results alone. **Before moving ahead with project development, verify:**

- The utility rate tariff is correct
    - Note that a site may have the option or may be required to switch to a different utility rate tariff when installing a PV, wind, CHP, or battery system
    - Contact your utility for more information
- Actual load data is used rather than a simulated load profile
- PV, wind, CHP, GHP, and battery costs and incentives are accurate for your location

  - There may be additional value streams not included in this analysis such as ancillary services or capacity payments

- Financial inputs are accurate, especially discount rate and utility escalation rate
- Other factors that can inform decision-making, but are not captured in this model, are considered. These may include:
  - roof integrity
  - shading considerations
  - obstacles to wind flow
  - ease of permitting
  - mission compatibility
  - regulatory and zoning ordinances
  - utility interconnection rules
  - availability of funding
- Multiple systems integrators are consulted, and multiple proposals are received. These will help to refine system architecture and projected costs and benefits. The REopt web tool results can be used to inform these discussions.

19 Off-grid Microgrids

By default, REopt optimizes systems to maximize grid-connected economics. Users have the option to instead model an entirely off-grid microgrid by toggling off the "Grid" technology option in the web tool. This differs from a resilience analysis, in which a facility is primarily grid-connected, but experiences a specified grid outage. The sections below detail the modified inputs, modeling changes, and outputs relevant to off-grid analyses. Default input values that are unique to off-grid modeling are detailed in relevant tables in Section 20.

19.1 Off-grid inputs

The user inputs described here are included or modified when modeling an off-grid microgrid. The system is assumed to be entirely isolated from a bulk power system and thus no utility- or grid-related inputs are required for off-grid analyses.

Technologies

REopt is capable of modeling an off-grid microgrid with solar PV, battery storage, and/or generators. Other technologies, including wind, CHP, and thermal energy storage cannot be modeled in an off-grid system.

Load Profile

In off-grid analyses, only electrical loads can be included; heating loads and cooling loads cannot be modeled.

Typical electrical load (units: kW per timestep): The load profile for off-grid analyses is assumed to be the aggregate load profile for all facilities that are to be served by the microgrid. For microgrids in rural Sub-Saharan Africa, NREL's Microgrid Load Profile Explorer tool[27] may be useful for generating hourly load profiles for various household types and commercial entities. The user can also use the DOE Commercial Reference Buildings, as described in Section 7.2, however these profiles are not based on building modeling specific to off-grid scenarios and therefore the user is advised to consider their relevance for the analysis being performed.

Minimum load met (units: % of annual load): The minimum load met represents the percentage of total annual electrical load that must be met. This optional input is unique to off-grid analyses and enables the user to potentially relax the general constraint that 100% of the typical electrical load must be met in every hour of the analysis year. If a value less than 100% is entered, the model selects the timestep(s) in which to shed load, if needed. For off-grid power systems that rely on PV, building a system for 100% availability during extended days of low solar resource can result in very large battery energy storage solutions and can therefore be considerably more expensive than systems that have a lower availability requirement. By relaxing the constraint on meeting all of the annual electrical load, the user can explore the tradeoff between total costs and availability.

Load operating reserve requirement (units: % of load): The load operating reserve requirement is the surplus operating capacity (as a percentage of load) that must be able to respond to an unexpected increase in load in any timestep. For example, if the modeled load in a given timestep is 10 kW and the load operating reserve requirement is 20%, REopt will ensure that there are available operating reserves to meet an extra 2 kW of load during that timestep. In REopt, operating reserves (commonly referred to as spinning reserves) can be supplied by curtailed PV, PV charging batteries in the current time step, stored energy in batteries, and/or spinning generators. A higher load operating reserve requirement provides a greater safety margin to ensure reliable electricity supply. This is particularly useful if the true load is expected to be more variable than the load profile supplied to REopt. A separate REopt input defines the operating reserve requirements to cover a sudden decrease in solar generation (described below).

Financial

Additional capital costs (units: upfront cost): The construction of off-grid microgrids often entails additional capital costs beyond the purchase of generation technologies. These costs can include land purchase costs, distribution network costs, powerhouse or battery container structure costs, and pre-operating expenses (e.g., site visits, system design, licensing, and feasibility studies). The user can enter these costs here to be included in the life-cycle cost analysis. The default cost is $0.

Additional annual costs (units: annual cost): Off-grid microgrids also often incur additional annual expenses beyond fuel costs, non-fuel operation and maintenance costs, and replacement costs. These can include labor costs, land lease costs, software costs, and any other ongoing

[27] Microgrid Load Profile Explorer Tool: https://data.nrel.gov/submissions/79

expenses not included in other cost inputs. REopt assumes any annual costs entered in this field escalate at the same rate as O&M costs (see Section 4.1).

PV

PV operating reserve requirement (units: % of PV generation): Operating reserve requirement as a percentage of solar PV generation in each timestep. The user input represents the percentage of solar generation that is assumed to potentially drop in any timestep, e.g., due to passing clouds. Operating reserves must be available to cover the user-specified drop in PV generation as well as a potential increase in load. Consider, for example, a microgrid with a 100-kW load in a given timestep, 50 kW of which is served by solar generation. If the load operating reserve requirement is 20% and the PV operating reserve requirement is 20%, then 20 kW (20% * 100 kW) of operating reserves are required to cover the potential increase in load and 10 kW (20% * 50 kW) of operating reserves are required to cover a potential decrease in PV generation, for a total of 30 kW of operating reserves required in that timestep. In REopt, operating reserves (commonly referred to as spinning reserves) can be supplied by available generation capacity from curtailed PV, PV charging batteries in the current time step, stored energy in the batteries, and/or spinning generators.

Generator

Generator size adjustment (units: % of peak load or *kW):* For off-grid analyses in the web tool, the size of the diesel generator is a user input and is not determined by REopt. The user can set the generator size to either a percentage of annual peak electrical load or a custom size. The default generator size is 200% of the peak electrical load. Although only a single generator is modeled, the capacity could be installed in two units (each sized at 100% of peak load). In this case, the default system would provide N+1 capacity reserve, or enough generator capacity to support the peak electrical load when one of the units is off-line for maintenance. In the REopt API, it is possible to optimally size a diesel generator in an off-grid analysis, but longer solve times should be expected.

Minimum turndown (units: % of rated capacity): The minimum generator loading as a percentage of its rated capacity. Generators are typically designed to operate at 50 percent capacity or higher. Continuously underloading a generator can decrease the useful life of the unit, increase O&M costs, and cause unplanned shutdowns.[28] By default, the generator's minimum turndown for off-grid analyses is set to 15% to limit the likelihood of infeasible solutions while avoiding unreasonable underloading.[29] As described above, we assume N+1 generator capacity reserve by default, and thus a 15% minimum turndown equates to one of the two assumed generators running at 30% minimum turndown.

Replacement year (units: years): The number of years the generator asset will be used before replacement. For off-grid analyses, the generator (and battery system) is assumed to be replaced once, in the specified replacement year. The replacement cost of a generator is assumed to be

[28] https://www.cat.com/en_US/by-industry/electric-power/Articles/White-papers/the-impact-of-generator-set-underloading.html

[29] The default generator minimum turndown for grid-connected "Resilience" scenarios is 0%. This input is modifiable in the REopt API, but is not exposed in the web tool for Resilience cases.

equal to its original installed cost. This input is unique to off-grid scenarios; for grid-connected evaluations, the backup diesel generator is assumed to last the entire analysis period.

The actual life of a generator depends on many factors, including the generator's detailed design, size, frequency at which it runs, typical loading capacity, climate, and maintenance schedule. If multiple generator replacements are anticipated, the following approach can be used to model the cost of these multiple replacements in REopt:

1. Calculate the "net present value" of all future replacements as:

$$NPV = \sum_{i=1}^{n} \frac{F_i}{(1+d)^i} \qquad \text{Equation 12}$$

   Where *i* is the project year in which the asset is replaced, *n* is the number of replacements, *d* is the discount rate, and *F* is the future cost of each replacement in \$/kW. *F* should account for inflation.

2. Add the NPV of future replacements to the installed capital cost, both in \$/kW.

3. Enter this sum as the generator installed cost (\$/kW) and set the replacement year equal to the analysis period (to ensure additional replacements are not modeled).

19.2 Off-grid model

Several additional constraints are included in the REopt model for off-grid analyses, as formulated in Appendix C, Section 1.4.10. These constraints implement load and solar PV operating (or spinning) reserve requirements and a minimum load met requirement.

19.3 Off-grid outputs

Several additional or modified outputs are reported for off-grid analyses, as described below.

Life cycle cost (LCC): The life cycle cost (LCC) for off-grid analyses includes technology capital costs, O&M costs, and generator fuel costs (similar to grid-connected analyses), as well as user-supplied "additional capital costs" and the net present value of any "additional annual costs. The LCC will also include climate and/or health costs if the user chooses to include those costs in the objective function (See Section 9.2.2) For *grid-connected* analyses, the LCC is calculated for a business-as-usual case (BAU), and the net-present value (NPV) of the investment is calculated as the difference between the LCC in the investment and BAU cases. In contrast, for off-grid analyses there is no "business-as-usual" case, and thus no BAU LCC nor NPV is calculated.

Levelized cost of electricity (LCOE): This project-level output is specific to off-grid analyses. The off-grid LCOE is calculated as:

$$LCOE = \frac{\frac{LCC}{pwf}}{AnnualGeneration} \qquad \text{Equation 13}$$

Where *LCC* is the life cycle cost over the analysis period, *pwf* is an annuity used to amortize the LCC into a constant annual cost (given the off-taker or owner's discount rate, depending on the ownership structure), and *AnnualGeneration* is the total microgrid generation in a year [kWh].

Breakdown of LCOE by cost component: The results page of the web tool also breaks down the LCOE into the following cost components: renewable energy capital expenses (includes the installed cost of the solar PV and battery systems and replacement costs and salvage value for battery systems), generator capital expenses (includes the generator installed cost, replacement costs, and salvage value), other capital expenses (as input by the user), fuel costs, operations & maintenance costs (for the PV and generator), and other annual costs (as input by the user). This breakdown provides insights into the most costly aspects of the microgrid and potential opportunities for cost savings.

20 The REopt Web Tool Default Values, Typical Ranges, and Sources

Table 29. Site and Utility Inputs, Default Values, Ranges, and Sources

Input	Default Value	Range	Source
CHP Standby charge based on CHP size ($/kW/month)	0	0–30	**Standby Rates for Customer-sited Resources; Issues, Considerations, and the Elements of Model Tariffs; 2009.** https://www.epa.gov/sites/production/files/2015-10/documents/standby_rates.pdf **Standby Rates for Combined Heat and Power Systems; Economic Analysis and Recommendations for Five States; 2014.** https://www.raponline.org/knowledge-center/standby-rates-for-combined-heat-and-power-systems-economic-analysis-and-recommendations-for-five-states/
Existing heating system efficiency (% HHV-basis)	80% 75%	50–95%	**U.S. DOE Commercial Reference Buildings** https://www.energy.gov/eere/buildings/commercial-reference-buildings
Max. boiler thermal capacity	1.25		This value is based on engineering judgment.
Solver optimality tolerance (%)	0.1% general 1% CHP 5% Off-grid	0.1% - 5%	Higher optimality tolerance values can be used when no solution is found within the model's timeout limit. The additional constraints implemented for CHP and off-grid analyses require a higher optimality tolerance default to increase the likelihood that the model will find a timely optimal solution.

Table 30. Load Profile Inputs, Default Values, Ranges, and Sources

Input	Default Value	Range	Source
Electric cooling plant coefficient of performance (COP) (kWt/kWe)	4.40 capacity <100 tons 4.69 capacity >100 tons	2–7	**Sweetser, R. (2020, June). Exergy Partners Corporation. *Personal Communication*.** **U.S. DOE Commercial Reference Buildings** https://www.energy.gov/eere/buildings/commercial-reference-buildings
Max. chiller thermal capacity as a factor of peak cooling load	1.25		This value is based on engineering judgment.
Minimum load met (%)	99.9%		Off-grid analyses only. The default value slightly lower than 100% reduces the likelihood of infeasible solutions.
Load operating reserve requirement (% of load in each timestep)	10%		Off-grid analyses only. The load operating reserve required is largely a user preference, based on the desired reliability of the system. Previous work has assumed 10% of the load must be covered by operating reserves. **Power Generation Planning of Galapagos' Microgrid Considering Electric Vehicles and Induction Stoves. Clairand, Jean-Michel, Mariano Arriaga, Claudio A. Canizares, and Carlos Alvarez-Bel. IEEE TRANSACTIONS ON SUSTAINABLE ENERGY, ACCEPTED OCTOBER 2018.** https://uwaterloo.ca/scholar/sites/ca.scholar/files/ccanizar/files/clairand_power_gen_planning_galapagos.pdf

Table 31. Financial Inputs, Default Values, Ranges, and Sources

Input	Default Value	Range	Source
Analysis period (years)	25	10–40	**2021 Annual Technology Baseline and Standard Scenarios. NREL, 2021.** https://atb.nrel.gov/ Defaults for Economic lifetime of distributed commercial renewable technologies used for NREL analyses vary. The 2021 Annual Technology Baseline includes options for 20 or 30 years. Typical internal REopt analyses use 25 years. **ASTM E917-17, Standard Practice for Measuring Life-Cycle Costs of Buildings and Building Systems, ASTM International, West Conshohocken, PA, 2017.** www.astm.org

Input	Default Value	Range	Source
			This ASTM standard uses a 25-year study period for most examples. **NREL's System Advisory Model (SAM)** uses a 25-year analysis period default. January 2021. https://sam.nrel.gov **Energy Independence and Security Act of 2007, Sec. 441. Public Law 110-140, 110th US Congress.** https://www.gpo.gov/fdsys/pkg/PLAW-110publ140/pdf/PLAW-110publ140.pdf Public building lifecycle costs are evaluated over a 40-year period in federal analyses.
Discount rate, nominal (%)	5.64%	2%–15%	**2021 Annual Technology Baseline and Standard Scenarios. NREL, 2021.** https://atb.nrel.gov/ The NREL 2021 Annual Technology Baseline has a projected 2022 WACC Nominal of 5.64% for Commercial PV and 6.33% for Land-based wind. Discount rate varies significantly between distributed PV and wind adopters. **NREL's System Advisory Model (SAM)** uses a default nominal discount rate, but warns the user to carefully consider using a custom rate. https://sam.nrel.gov **Energy Price Indices and Discount Factors for Life-Cycle Cost Analysis – 2021 Annual Supplement to NIST Handbook 135. DOE, April 2021.** https://nvlpubs.nist.gov/nistpubs/ir/2021/NIST.IR.85-3273-36.pdf Federal projects use a nominal discount rate of 1.4% based on 2021 NIST Handbook.
Effective tax rate (%)	26% 21% federal +5% state	15%–21% for federal corporate income taxes plus 0%–12% state corporate income taxes	**2021 Annual Technology Baseline and Standard Scenarios. NREL, 2021.** https://atb.nrel.gov/ Tax rate (federal and state) used for NREL analyses. **2021 Instructions for Form 1120: U.S. Corporation Income Tax Return. U.S. Department of the Treasury, Internal Revenue Service, January 2022.** https://www.irs.gov/pub/irs-pdf/i1120.pdf Federal corporate income tax rate of a flat 21% is listed under Schedule J, Tax Computation and Payment on page 19.

Input	Default Value	Range	Source
			State Corporate Income Tax Rates and Brackets for 2022. Tax Foundation, January 2022. **https://taxfoundation.org/state-corporate-income-tax-rates-brackets-2022/** State corporate income tax rates and brackets listed for 2022. Local income and state and local property taxes should also be taken into account.
Electricity cost escalation rate, nominal (%)	1.9%	1.5% – 2.4%	The nominal electricity cost escalation rate is provided explicitly in the U.S. Energy Information Administration's (EIA) Annual Energy Outlook and can also be calculated implicitly by combining the NIST Handbook's real electricity cost escalation rates with expected inflation rates. **Annual Energy Outlook 2022 – Energy Prices by Sector and Source. EIA, January 2022.** https://www.eia.gov/outlooks/aeo/data/browser/#/?id=3-AEO2022&cases=ref2022&sourcekey=0 The EIA predicts a 1.9% average nominal annual commercial electricity escalation rate from 2021-2046 in their reference case scenario. Regional variation yields a range of annual electricity cost escalation rates from 1.5% to 2.4%.
Existing boiler fuel cost escalation rate, nominal (%)	3.4%	3.3% – 3.5%	The nominal natural gas cost escalation rate is provided explicitly in the EIA's Annual Energy Outlook. **Annual Energy Outlook 2019 – Energy Prices by Sector and Source. EIA, January 2019.** https://www.eia.gov/outlooks/aeo/data/browser/#/?id=3-AEO2019&region=1-0&cases=ref2019&start=2020&end=2045&f=A&linechart=ref2019-d111618a.5-3-AEO2019.1-0&map=ref2019-d111618a.4-3-AEO2019.1-0&ctype=linechart&sourcekey=0 The EIA predicts a 3.3% and 3.5% average nominal annual commercial and industrial natural gas escalation rate from 2020-2045, respectively in their reference case scenario, assuming an inflation rate of 1.9%.
CHP fuel cost escalation rate, nominal (%)	3.4%	3.3% – 3.5%	The nominal natural gas cost escalation rate is provided explicitly in the EIA's Annual Energy Outlook. **Annual Energy Outlook 2019 – Energy Prices by Sector and Source. EIA, January 2019.** https://www.eia.gov/outlooks/aeo/data/browser/#/?id=3-AEO2019&region=1-0&cases=ref2019&start=2020&end=2045&f=A&linechart=ref2019-d111618a.5-3-AEO2019.1-0&map=ref2019-

Input	Default Value	Range	Source
			d111618a.4-3-AEO2019.1-0&ctype=linechart&sourcekey=0 The EIA predicts a 3.3% and 3.5% average nominal annual commercial and industrial natural gas escalation rate from 2020-2045, respectively in their reference case scenario, assuming an inflation rate of 1.9%.
Generator fuel cost escalation rate, nominal (%)	2.7%		The nominal distillate fuel oil cost escalation rate is provided explicitly in the U.S. Energy Information Administration's (EIA) Annual Energy Outlook. **Annual Energy Outlook 2020 – Energy Prices by Sector and Source. EIA, January 2020.** https://www.eia.gov/outlooks/aeo/data/browser/#/?id=3-AEO2020&cases=ref2020&sourcekey=0 The EIA predicts a 2.7% average nominal annual commercial escalation rate from 2020-2045 in their reference case scenario. Regional variation yields a range of annual distillate fuel cost escalation rates from 2.4% to 3.0%.
O&M cost escalation rate (%)	2.5%	-0.2% – 8.3%.	O&M costs are assumed to escalate at inflation rate. **2021 Annual Technology Baseline and Standard Scenarios. NREL, 2021.** https://atb.nrel.gov/ NREL analyses assume an inflation rate of 2.5%. **Energy Price Indices and Discount Factors for Life-Cycle Cost Analysis – 2021 Annual Supplement to NIST Handbook 135. DOE, April 2021.** https://nvlpubs.nist.gov/nistpubs/ir/2021/NIST.IR.85-3273-36.pdf Federal projects use an inflation rate of -1.5%. **Historical Inflation Rates: 1914-2022. U.S. Inflation Calculator, January 2021.** http://www.usinflationcalculator.com/inflation/historical-inflation-rates/ Lists monthly U.S. inflation rates from 1914-2022. Inflation rate average for 2021 listed as 4.7%. Since 2010, inflation rates have ranged from -0.2% to 8.3%.

Table 32. Emissions Inputs, Default Values, Ranges, and Sources

<table>
<tr><th>Input</th><th>Default Value</th><th>Range</th><th>Source</th></tr>
<tr><td>CO2 emissions factor for utility-sourced electricity (lb/kWh)</td><td>hourly or annual</td><td>0.1 – 2.0</td><td>Hourly value used from AVERT tool: AVERT, 2019. “AVoided Emissions and geneRation Tool (AVERT) User Manual”. Version 2.3. May 2019. https://www.epa.gov/statelocalenergy/avoided-emissions-and-generation-tool-avert.

For Hawaii and Alaska, eGRID value used: eGRID, 2016. “Emissions & Generation Resource Integrated Database (eGRID)”. Last modified version is ‘egrid2016_data.xlsx’ spreadsheet from 2016. https://www.epa.gov/energy/emissions-generation-resource-integrated-database-egrid.</td></tr>
<tr><td>Boiler natural gas emissions factor (lb/MMBtu)</td><td>116.9</td><td>100 - 140</td><td>EPA, 2015. “Fuel and Carbon Dioxide Emissions Savings Calculation Methodology for Combined Heat and Power Systems”. U.S. Environmental Protection Agency Combined Heat and Power Partnership. Feb. 2015. https://www.epa.gov/chp/fuel-and-carbon-dioxide-emissions-savings-calculation-methodology-combined-heat-and-power</td></tr>
<tr><td>CHP natural gas emissions factor (lb/MMBtu)</td><td>116.9</td><td>100 - 140</td><td>Value depends on the type of fuel for CHP. The default assumes natural gas is the fuel.
<table>
<tr><td>Fuel Type</td><td>CO2 Emissions Factor, lb/MMBtu</td></tr>
<tr><td>Natural Gas[1]</td><td>116.9</td></tr>
<tr><td>Landfill gas, other biomass gasses[2]</td><td>114.8</td></tr>
<tr><td>Propane[2]</td><td>138.6</td></tr>
</table>
1. EPA, 2015. “Fuel and Carbon Dioxide Emissions Savings Calculation Methodology for Combined Heat and Power Systems”. U.S. Environmental Protection Agency Combined Heat and Power Partnership. Feb. 2015. https://www.epa.gov/chp/fuel-and-carbon-dioxide-emissions-savings-calculation-methodology-combined-heat-and-power
2. EPA, 2018. “Emission Factors for Greenhouse Gas Inventories”. Last modified March 2018. https://www.epa.gov/sites/production/files/2018-03/documents/emission-factors_mar_2018_0.pdf</td></tr>
</table>

Table 33. PV Inputs, Default Values, Ranges, and Sources

Input	Default Value	Range	Source
System capital cost ($/kW)	$1592	$1550 – $3900	**2021 Annual Technology Baseline and Standard Scenarios. NREL, 2021.** https://atb.nrel.gov/

Input	Default Value	Range	Source
			NREL analyses project a moderate 2022 distributed commercial PV CAPEX of $1,592/kW. **Winter 2021/2022 Solar Industry Update. NREL, January 11, 2022.** https://www.nrel.gov/docs/fy22osti/81900.pdf From H2 2020 to H2 2021, price data for select states fell to $3900/kW for 2.5-10 kW systems, remained flat at $3380/kW for 10-100 kW systems, fell to $2360/kW for 100-500 kW systems, and rose to $1880/kW for systems 500-5000 kW. **U.S. Solar Photovoltaic System and Energy Storage Cost Benchmark: Q1 2020. NREL, January 2021.** https://www.nrel.gov/docs/fy21osti/77324.pdf The resource lists NREL's bottom-up cost calculations for residential, commercial, and utility-scale PV. Commercial PV is calculated to average $1.72/W in Q1 2020.
O&M cost ($/kW/year)	$17	$12 –$13	**2021 Annual Technology Baseline and Standard Scenarios. NREL, 2021.** https://atb.nrel.gov/ Fixed O&M expenses for distributed commercial PV in 2022 assumed for NREL analyses.
Array azimuth	180° or 0°	0° - 360°	The default value of 180° assumes the array is in the northern hemisphere and is facing due south. When the array is in the southern hemisphere, the assumption is that it is facing due north and the array azimuth default value changes to 0°. **PVWatts Version 5 Manual. Dobos, Aron P., NREL, September 2014.** https://www.nrel.gov/docs/fy14osti/62641.pdf **Current PVWatts Online Help Manual. May 2022.** https://pvwatts.nrel.gov/index.php PVWatts uses a default azimuth of 180° in the northern hemisphere and 0° in the southern hemisphere. **U.S. Solar Photovoltaic System and Energy Storage Cost Benchmark: Q1 2020. NREL, January 2021.** https://www.nrel.gov/docs/fy21osti/77324.pdf The resource specifies an array azimuth of 180°.
Array tilt – Rooftop, Fixed	10°	0° – 60°	Rooftop PV is usually mounted at 10-20 degrees on a flat roof to reduce wind loading and shading losses. PV on a sloped roof is typically installed parallel to the roof's surface, though azimuth and tilt angle can be adjusted if desired. **Current PVWatts online Help Manual. May 2022.** https://pvwatts.nrel.gov/index.php For an array installed on a building's roof, you may want to choose a tilt angle equal to the roof pitch.

Input	Default Value	Range	Source
			U.S. Solar Photovoltaic System Cost Benchmark: Q1 2018. NREL, November 2018. https://www.nrel.gov/docs/fy19osti/72399.pdf The resource specifies an array tilt of 10°. **Best Practices for Operation and Maintenance of Photovoltaic and Energy Storage Systems; 3rd Edition. 2018.** https://www.nrel.gov/docs/fy19osti/73822.pdf For a ballasted system on a flat roof, a low tilt angle (usually 10° tilt) is required to reduce wind loads.
Array tilt – Ground mount, Fixed	Tilt = latitude	0° – 90°	The default value assumes the tilt is equal to the latitude of the site location. If the site is in the southern hemisphere, this default is the absolute value of the latitude. **PVWatts Version 5 Manual. Dobos, Aron P., NREL, September 2014.** https://www.nrel.gov/docs/fy14osti/62641.pdf **Current PVWatts Online Help Manual. May 2022.** https://pvwatts.nrel.gov/index.php PVWatts uses a default equal to the site latitude. **Advanced Photovoltaic Installations. Balfour, John, Michael Shaw, and Nicole Bremer Nash. The Art and Science of Photovoltaics. 2013.** https://books.google.com/books?id=t5uTktdsu3AC&pg=PA77&lpg=PA77&dq=pv+geometry+flat+roof&source=bl&ots=K4v99ljXqq&sig=spZ0uf0Zdh-zrK66Zldm6UN6ECs&hl=en&sa=X&ved=0ahUKEwiErOjBlevVAhUKw4MKHTzoCMMQ6AEIcDAM#v=onepage&q=pv%20geometry%20flat%20roof&f=false Page 71 describes how in order to maximize annual yield, the array should be tilted at the site's latitude. Decreasing the tilt angle increases summer yield while increasing tilt angle increases winter yield. To maximize output in summer, it should be tilted at (latitude – 15)°. To maximize output in winter, it should be tilted at (latitude + 15) °.
Array tilt – Ground mount, 1-Axis Tracking	0	0° – 10° based on site slope	**PVWatts Version 5 Manual. Dobos, Aron P., NREL, September 2014.** https://www.nrel.gov/docs/fy14osti/62641.pdf **Current PVWatts online Help Manual. May 2022.** https://pvwatts.nrel.gov/index.php For arrays with one-axis tracking, the tilt angle is the angle from horizontal of the tracking axis. For flat ground, the tilt would be 0°, or parallel to the ground's surface. For installations that are not on flat ground, the tilt would be the slope of the hillside. **Solar Balance-of-System: To Track or Not to Track, Part 1. Greentech Media,** https://www.greentechmedia.com/articles/read/solar-balance-of-system-to-track-or-not-to-track-part-i

Input	Default Value	Range	Source
			One-axis tracking systems rotate over an axis that is parallel to the ground's surface.
DC to AC ratio	1.2	1.0 – 1.5	**PVWatts Version 5 Manual. Dobos, Aron P., NREL, September 2014.** https://www.nrel.gov/docs/fy14osti/62641.pdf **Current PVWatts Online Help Manual. May 2022.** https://pvwatts.nrel.gov/index.php PVWatts inputs list 1.2 as the default. The help manual also lists a default DC/AC ratio of 1.2. The 2014 technical manual lists a ratio of 1.1.
Incentives	26% ITC, 5 year MACRS 100% Bonus depreciation		**Database of State Incentives for Renewables & Efficiency. NC Clean Energy Tech Center, accessed January 2022.** http://www.dsireusa.org/ Incentives are available at the federal, state, and local level. This site provides searchable specifics about incentives based on location. The following federal incentives are default values in the REopt web tool: **Business Energy Investment Tax Credit. Database of State Incentives for Renewables & Efficiency, NC Clean Energy Tech Center, February 2021.** https://programs.dsireusa.org/system/program/detail/658/business-energy-investment-tax-credit-itc In 2022, a federal 26% investment tax credit is available to solar projects regardless of size, with no maximum incentive for solar technologies. The credit was previously 30%. **Modified Accelerated Cost-Recovery System. Database of State Incentives for Renewables & Efficiency, NC Clean Energy Tech Center, August 2018.** http://programs.dsireusa.org/system/program/detail/676 Solar projects are eligible for accelerated depreciation deductions over a 5-year period, with bonus depreciation of 100% in the first year.
System losses – General			Total losses calculated as (1 - (1-loss1)*(1-loss2)*…*(1-lossN))
System losses – Soiling	2%	2% – 25%	**PVWatts Version 5 Manual. Dobos, Aron P., NREL, September 2014.** https://www.nrel.gov/docs/fy14osti/62641.pdf **Current PVWatts online Help Manual. May 2022.** https://pvwatts.nrel.gov/index.php PVWatts applies a default soiling loss of 2%. **Performance Parameters for Grid-Connected PV Systems. NREL, February 2005.** https://www.nrel.gov/docs/fy05osti/37358.pdf

Input	Default Value	Range	Source
			Table 1 lists a typical soiling AC derate factor as 0.95, with a typical range of 0.75-0.98. These values correspond to a typical soiling loss of 5% with a typical range of 2%-25%.
System losses – Shading	3%	0% – 30%	**PVWatts Version 5 Manual. Dobos, Aron P., NREL, September 2014.** https://www.nrel.gov/docs/fy14osti/62641.pdf **Current PVWatts Online Help Manual. May 2022.** https://pvwatts.nrel.gov/index.php PVWatts applies a default shading loss of 3%. **Photovoltaic Shading Testbed for Module-Level Power Electronics: 2016 Performance Data Update. NREL and PV Evolution Labs, September 2016.** https://www.nrel.gov/docs/fy16osti/62471.pdf Based on a survey of shading of residential PV systems, this study classifies light shading as <15% annual shading (7.6% is representative of typical light shading), moderate shading as 15%-20% annual shading (19% is representative of typical moderate shading), and heavy shading as >20% annual shading (25.5% is representative of typical heavy shading). If the shading increases to >30% of the modules in a string, the maximum power point tracking (MPPT) minimum voltage would be reached. **Performance Parameters for Grid-Connected PV Systems. NREL, February 2005.** https://www.nrel.gov/docs/fy05osti/37358.pdf Table 1 lists a typical shading derate factor as 0.975 for fixed-tilt rack-mounted systems. These values correspond to a typical shading loss of 2.5%.
System losses – Snow	0%	0% – 15% typical in US, 0% – 100% possible	**PVWatts Version 5 Manual. Dobos, Aron P., NREL, September 2014.** https://www.nrel.gov/docs/fy14osti/62641.pdf **Current PVWatts Online Help Manual. May 2022.** https://pvwatts.nrel.gov/index.php PVWatts applies a default snow loss of 0%. **Integration, Validation, and Application of a PV Snow Coverage Model in SAM. NREL, August 2017.** https://www.nrel.gov/docs/fy17osti/68705.pdf Figures 2 and 3 show estimated snow losses for cities and regions, respectively, of the United States. Appendices A and B provide the respective data in more detail.
System losses – Mismatch	2%	1.5% – 3%	**PVWatts Version 5 Manual. Dobos, Aron P., NREL, September 2014.** https://www.nrel.gov/docs/fy14osti/62641.pdf **Current PVWatts Online Help Manual. May 2022.** https://pvwatts.nrel.gov/index.php PVWatts applies a default mismatch loss of 2%.

Input	Default Value	Range	Source
			Performance Parameters for Grid-Connected PV Systems. NREL, February 2005. https://www.nrel.gov/docs/fy05osti/37358.pdf Table 1 lists a typical mismatch derate factor as 0.98, with a typical range of 0.97-0.985. These values correspond to a typical mismatch loss of 2% with a typical range of 1.5%-3%.
System losses –Wiring	2%	0.7% – 2%	**PVWatts Version 5 Manual. Dobos, Aron P., NREL, September 2014.** https://www.nrel.gov/docs/fy14osti/62641.pdf **Current PVWatts Online Help Manual. May 2022.** https://pvwatts.nrel.gov/index.php PVWatts applies a default wiring loss of 2%. **Performance Parameters for Grid-Connected PV Systems. NREL, February 2005.** https://www.nrel.gov/docs/fy05osti/37358.pdf Table 1 lists a typical wiring derate factor as 0.99, with a typical range of 0.98-0.993. These values correspond to a typical wiring loss of 1% with a typical range of 0.7%-2%.
System losses – Connection	0.5%	0.3% – 0.1%	**PVWatts Version 5 Manual. Dobos, Aron P., NREL, September 2014.** https://www.nrel.gov/docs/fy14osti/62641.pdf **Current PVWatts Online Help Manual. May 2022.** https://pvwatts.nrel.gov/index.php PVWatts applies a default connection loss of 0.5%. **Performance Parameters for Grid-Connected PV Systems. NREL, February 2005.** https://www.nrel.gov/docs/fy05osti/37358.pdf Table 1 lists a typical diodes and connections derate factor as 0.995, with a typical range of 0.99-0.997. These values correspond to a typical connection loss of 0.5% with a typical range of 0.3%-1%.
System losses – Light-induced degradation (LID)	1.5%	0.3% – 10%	**PVWatts Version 5 Manual. Dobos, Aron P., NREL, September 2014.** https://www.nrel.gov/docs/fy14osti/62641.pdf **Current PVWatts Online Help Manual. May 2022.** https://pvwatts.nrel.gov/index.php PVWatts applies a default light-induced degradation loss of 1.5%. **Performance Parameters for Grid-Connected PV Systems. NREL, February 2005.** https://www.nrel.gov/docs/fy05osti/37358.pdf Table 1 lists a typical LID derate factor as 0.98, with a typical range of 0.90-0.99. These values correspond to a typical mismatch loss of 2% with a typical range of 1%-10%.

Input	Default Value	Range	Source
System losses – Nameplate Rating	1%	-5% – 15%	**PVWatts Version 5 Manual. Dobos, Aron P., NREL, September 2014.** https://www.nrel.gov/docs/fy14osti/62641.pdf **Current PVWatts Online Help Manual. May 2022.** https://pvwatts.nrel.gov/index.php PVWatts applies a default nameplate rating loss of 1%. **Performance Parameters for Grid-Connected PV Systems. NREL, February 2005.** https://www.nrel.gov/docs/fy05osti/37358.pdf Table 1 lists a typical nameplate rating derate factor as 1.0, with a typical range of 0.85-1.05. These values correspond to a typical nameplate rating loss of 0% with a typical range of -5%-15%.
System losses – Age	0%	0% – 100%	**PVWatts Version 5 Manual. Dobos, Aron P., NREL, September 2014.** https://www.nrel.gov/docs/fy14osti/62641.pdf **Current PVWatts Online Help Manual. May 2022.** https://pvwatts.nrel.gov/index.php PVWatts applies a default loss due to age of 0%.
System losses – Availability	3%	0.5% – 100%	**PVWatts Version 5 Manual. Dobos, Aron P., NREL, September 2014.** https://www.nrel.gov/docs/fy14osti/62641.pdf **Current PVWatts Online Help Manual. May 2022.** https://pvwatts.nrel.gov/index.php PVWatts applies a default availability loss of 3%. **Performance Parameters for Grid-Connected PV Systems. NREL, February 2005.** https://www.nrel.gov/docs/fy05osti/37358.pdf Table 1 lists a typical availability derate factor as 0.98, with a typical range of 0-0.995. These values correspond to a typical availability loss of 2% with a typical range of 0.5%-100%.
PV operating reserve requirement (% of PV generation in each time step)	25%		Off-grid analyses only. The PV operating reserve required is largely a user preference, based on the desired reliability of the system. Previous work has assumed 25% of solar power must be covered by operating reserves. **Renewable Energy Deployment in Canadian Arctic. Das, Indrajit and Claudio Canizares. World Wildlife Fund (WWF) Canada. 2016.** https://wwf.ca/wp-content/uploads/2020/03/Fuelling-change-in-the-arctic_2016.pdf **Power Generation Planning of Galapagos' Microgrid Considering Electric Vehicles and Induction Stoves. Clairand, Jean-Michel, Mariano Arriaga, Claudio A. Canizares, and Carlos Alvarez-Bel. IEEE Transactions on Sustainable Energy, Accepted October 2018.**

Input	Default Value	Range	Source
			https://uwaterloo.ca/scholar/sites/ca.scholar/files/ccanizar/files/clairand_power_gen_planning_galapagos.pdf

Table 34. Battery Storage Inputs, Default Values, Ranges, and Sources

Note: All values listed assume the use of lithium-ion battery systems

Input	Default Value	Range	Source
Energy capacity cost ($/kWh)	$388	$292 – $688	**U.S. Energy Storage Monitor: Q4 2021 Full Report. Wood Mackenzie Power & Renewables and the Energy Storage Association, December 2021.** This analysis starts with Wood Mackenzie's all-inclusive cost of system, installation, normal interconnection, and metering costs to be $1,550/kW for a non-residential behind-the-meter 2-hour system, with a cost range of $1,175 - $2,650/kW. To determine energy capacity and energy demand components of the cost, the system can be assumed to have an energy:power ratio of 2:1 (i.e. 2 kWh:1kW), the resulting median costs are approximately $388/kWh and $775/kW (with ranges of 294-688 kWh and 565-1325 kW) **Lazard's Levelized Cost of Storage Analysis – Version 7. October 2021.** https://www.lazard.com/media/451418/lazards-levelized-cost-of-storage-version-60.pdf Key Assumptions table gives Initial Capital cost for a 2-hr Commercial & Industrial battery of $292-$346/kWh and $43-$59/kW-AC
Power capacity cost ($/kW)	$775	$43 – $1325	See above description of basis for energy capacity cost.
Battery energy capacity replacement cost ($/kWh)	$220	$162 – $340	**U.S. Energy Storage Monitor: Q4 2021 Full Report. Wood Mackenzie Power & Renewables and the Energy Storage Association, December 2021.** Woods Mackenzie predicts a decline in price of 9% in the next 2 years for front-of-the meter storage, but more flat costs for behind-the-meter, due to supply constraints and increased upstream prices, in the 3% decline range. Replacement costs need to be estimated for 10 years out. Conservatively, decline may be expected in the 5.5% per year range. **Energy Storage Technology and Cost Characterization Report. Pacific Northwest National Laboratory. July 2019** https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-28866.pdf

Input	Default Value	Range	Source
			A cost drop of 5% per year was assumed to be a conservative estimate for batteries on the lower end of the cost range. This is in light of significant cost drops seen in the past 10 years.
Energy capacity replacement year	10	9 – 20	Because the replacement timeline for Li-ion batteries is impacted by the SOC at which it is utilized, the replacement year is difficult to predict. The REopt web tool does not currently account for battery degradation or loss of capacity over time in its dispatch and energy/power calculations, but allows the user to input a replacement year. The Year 10 replacement default assumes that the technology for this replacement will have improved to the point that it will last for the remaining 15 years of the default 25-year analysis period. **Economic Analysis Case Studies of Battery Energy Storage with SAM. NREL, November 2015.** https://www.nrel.gov/docs/fy16osti/64987.pdf Uses the Tesla Powerwall specifications as an example and estimates that it will last 5 years longer than its 10-year warranty. At one cycle per day, this amounts to approximately 5,475 cycles. **Energy Storage Technology and Cost Characterization Report. Pacific Northwest National Laboratory. July 2019** https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-28866.pdf A survey of the literature suggests the lower end of the typical suggested range of 10-20 life years.
Power capacity replacement cost ($/kW)	$440	$76 – $653	See above description of basis for energy capacity replacement cost.
Power capacity replacement year	10	9 – 20	See above description of basis for energy capacity replacement year.
Rectifier efficiency (%)	96%		**An integrated approach for the analysis and control of grid connected energy storage systems. Journal of Energy Storage, Volume 5, February 2016.** http://www.sciencedirect.com/science/article/pii/S2352152X15300335 Depending on the SOC, the converter efficiency of a 100kW/50kWh lithium-ion system was found to sit around 96% for SOCs of 30-100%, as illustrated in Figure 14. The efficiency of this converter is applied to both the inverter and rectifier in the REopt web tool.

Input	Default Value	Range	Source
Round trip efficiency (%)	97.5%	95% – 98%	**An integrated approach for the analysis and control of grid connected energy storage systems. Journal of Energy Storage, Volume 5, February 2016.** http://www.sciencedirect.com/science/article/pii/S2352152X15300335 Depending on the SOC, the battery efficiency of a 100kW/50kWh lithium-ion system was found to vary between 97% and 98% for SOCs of 30%-100%, as illustrated in Figure 14. **Lithium Batteries and Other Electrochemical Storage Systems. Glazie, Christian and Geniès, Sylvie, August 2013.** http://onlinelibrary.wiley.com/doi/10.1002/9781118761120.ch6/pdf The efficiency depends on the battery's state of charge and it's charge/discharge conditions (voltage, rate of charge/discharge, temperature), especially at high or low SOC. The following values give average efficiencies at mid-range SOCs. 95% for C-$LiFePO_4$ – see Section 6.2.18. 98% for C-$Li(Co,Ni)O_2$ – see Section 6.2.18.
Inverter efficiency (%)	96		**An integrated approach for the analysis and control of grid connected energy storage systems. Journal of Energy Storage, Volume 5, February 2016.** http://www.sciencedirect.com/science/article/pii/S2352152X15300335 Depending on the SOC, the converter efficiency of a 100kW/50kWh lithium-ion system was found to sit around 96% for SOCs of 30-100%, as illustrated in Figure 14. The efficiency of this converter is applied to both the inverter and rectifier in the REopt web tool.
Minimum state of charge (%)	20	15% – 30%	**An integrated approach for the analysis and control of grid connected energy storage systems. Journal of Energy Storage, Volume 5, February 2016.** http://www.sciencedirect.com/science/article/pii/S2352152X15300335 When the state of charge of a lithium-ion battery drops below 20%, the voltage drops rapidly and impedance, which reduces round trip efficiency and generates heat, so optimal performance is achieved above 20% SOC.
Initial state of charge (%)	50% general 100% Off-grid		For off-grid scenarios, the battery is assumed to start fully charged. This avoids oversizing the battery solely to supply power during the first several hours of the modeled year of operations, during which time solar PV would not be generating any power.
Incentives	0% ITC, 7 year MACRS		**Database of State Incentives for Renewables & Efficiency. NC Clean Energy Tech Center, accessed January 2022.**

Input	Default Value	Range	Source
	100% Bonus deprecia tion		http://www.dsireusa.org/ Incentives are available at the federal, state, and local level. This site provides searchable specifics about incentives based on location. The following federal incentives are default values in the REopt web tool: The Federal ITC for batteries **Business Energy Investment Tax Credit. Database of State Incentives for Renewables & Efficiency, NC Clean Energy Tech Center, February 2021.** https://programs.dsireusa.org/system/program/detail/658/business-energy-investment-tax-credit-itc The default for percentage-based incentives is $0, corresponding to the default of the battery charging from the grid. New Tax laws concerning battery systems are pending. Please consult current rules. The 2022 Federal 26% ITC is generally understood to be available to batteries charged 100% by eligible renewable energy technologies, including solar and wind, when they are installed as part of a renewable energy system. Batteries charged by a renewable energy system 75%-99% of the time are eligible for that portion of the ITC. For example, a system charged by renewable energy 80% of the time is eligible for the 26% ITC multiplied by 80%, which equals a 20.8% ITC instead of 26%. **Federal Tax Incentives for Energy Storage Systems. National Renewable Energy Laboratory. January 2018.** https://www.nrel.gov/docs/fy18osti/70384.pdf Batteries charged at least 75% by eligible RE technologies are eligible for accelerated depreciation deductions over a 5-year period, with a bonus depreciation of 100% in the first year. Batteries charged 0%-75% by RE are eligible for a 7-year depreciation schedule.

Table 35. Wind Inputs, Default Values, Ranges, and Sources

Input	Default Value	Range	Source
Wind size class	Comm (21 kW-100 kW	2.5 kW–2,000 kW	Wind Class size options, and the representative turbine sizes, are Residential 0-20 kW (2.5 kW), Commercial 21-100 kW (100 kW), Midsize 101-999 kW (250 kW) and Large ≥ 1000 kW (2,000 kW). **Distributed Wind Market Report: 2021 Edition.** Alice Orrell, Kamila Kazimierczuk, and Lindsay Sheridan of Pacific Northwest National Laboratory. August 2021. https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-31729.pdf **Benchmarking US Small Wind Costs with the Distributed Wind Taxonomy**. AC Orrell and EA Poehlman. Pacific Northwest National Laboratory. September 2017. https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-26900.pdf
System capital cost ($/kW) Class	Comm $4,300	Res – $5,675 Comm – $4,300 Midsize – $2,766 Large – $2,239	Wind CAPEX Defaults change depending on the Wind Class size chosen: Residential ($5,675/kW), Commercial ($4,300/kW), Midsize ($2,766/kW) and Large ($2,239/kW). If no Wind Class is chosen, the default is the Commercial size, which has a default of $4,300. **2020 Cost of Wind Energy Review, Tyler Stehly and Patrick Duffy, NREL, January 2022** https://www.nrel.gov/docs/fy22osti/81209.pdf Reults in this report are used for the Residential and Commercial default system capital costs. Midsize and Large class defaults are taken from NREL research that is not yet published. **Distributed Wind Market Report: 2021 Edition.** Alice Orrell, Kamila Kazimierczuk, and Lindsay Sheridan of Pacific Northwest National Laboratory. August 2021. https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-31729.pdf This resource gives average costs over a ten year period. **Land-Based Wind Market Report: 2021 Edition.** Ryan Wiser and Mark Bolinger. Lawrence Berkeley National Laboratory. August 2021. https://emp.lbl.gov/sites/default/files/land-based_wind_market_report_2021_edition_final.pdf The capacity- weighted average installed project cost within the 2020 sample was $1,460/kW, for projects up to greater than 200 MW, representing larger installations that can take advantage of economies of scale.

Input	Default Value	Range	Source
			2021 Annual Technology Baseline and Standard Scenarios. NREL, 2021. https://atb.nrel.gov/ The 2021 NREL ATB projects 2022 moderate CAPEX of $1,303, but this also assumes a large installation.
O&M cost ($/kW/year)	$35	$33–$59	**2020 Cost of Wind Energy Review, , Tyler Stehly and Patrick Duffy, NREL, January 2022** https://www.nrel.gov/docs/fy22osti/81209.pdf $35/kW/year **Land-Based Wind Market Report: 2021 Edition.** Ryan Wiser and Mark Bolinger. Lawrence Berkeley National Laboratory. August 2021. https://emp.lbl.gov/sites/default/files/land-based_wind_market_report_2021_edition_final.pdf $33/kW/yr - $59 kW/yr **2021 Annual Technology Baseline and Standard Scenarios. NREL, 2021.** https://atb.nrel.gov/ The NREL 2021 ATB projects a 2022 moderate O&M cost of $42/kW/yr.
Incentives	26% ITC for small wind to 100 kW and 18% for larger wind 5 year MACRS 100% bonus depreciation		**Database of State Incentives for Renewables & Efficiency. NC Clean Energy Tech Center, accessed January 2022.** http://www.dsireusa.org/ Incentives are available at the federal, state, and local level. This site provides searchable specifics about incentives based on location. The following federal incentives are default values in the REopt web tool: **Business Energy Investment Tax Credit (ITC). Database of State Incentives for Renewables & Efficiency, NC Clean Energy Tech Center, February 2021.** https://programs.dsireusa.org/system/program/detail/658/business-energy-investment-tax-credit-itc In 2022, a federal 26% investment tax credit is available to wind projects up to 100kW in capacity and 18% for larger wind systems. The ITC is discontinued at the end of 2022 for larger wind systems. **Modified Accelerated Cost-Recovery System (MACRS). Database of State Incentives for Renewables & Efficiency, NC Clean Energy Tech Center, August 2018.** http://programs.dsireusa.org/system/program/detail/676 Wind projects are eligible for accelerated depreciation deductions over a 5-year period, with bonus depreciation of 100% in the first year. The provision which defines ITC technologies as eligible also adds the general term "wind"

Input	Default Value	Range	Source
			as an eligible technology, extending the five-year schedule to large wind facilities as well.

Table 36. Resilience Evaluations- Load Profile Inputs, Default Values, Ranges, and Sources

Input	Default Value	Range	Source
Critical load factor (%)	50%	10%–100%	The critical load varies widely based on building use.

Table 37. Resilience Evaluations- Generator Inputs, Default Values, Ranges, and Sources

Input	Default Value	Range	Source
Install cost ($/kW)	$500	$238-$800	**2019 RSMeans Building Construction Cost Data. 77th Annual Edition. Gordian Group. Reference: Packaged Generator Assemblies. Engine Generators. Diesel-Engine-Driven Generator Sets.** Total installing contractor costs, including overhead and profit, range from $238/kW for a 500 kW system to $527/kW for a 30 kW system. **Lazard's Levelized Cost of Energy Analysis—Version 11.0. November 2017.** (NOTE: 2020 version doesn't include diesel analysis) https://www.lazard.com/media/450337/lazard-levelized-cost-of-energy-version-110.pdf For an output of 250-1000 kW, the total capital costs average $500-$800/kW. Costs may assume Tier 4 compliance costs of adding emission control systems for prime applications as well as emergency backup.
Diesel cost ($/gal)	$3	$2.50-$3.27	**Cost Reference Guide for Construction Equipment: The Standard Reference for Estimating Owning and Operating Costs for all Classes of Construction Equipment. 1st Half 2019. EquipmentWatch.** Diesel = $3.27/gal **Lazard's Levelized Cost of Energy Analysis—Version 11.0. November 2017.** (NOTE: 2020 version doesn't include diesel analysis) https://www.lazard.com/media/450337/lazard-levelized-cost-of-energy-version-110.pdf Diesel price of ~$2.50/gal
Fuel availability (gallons)	660 general No limit Off-grid	1.4-660	**National Fire Prevention Association code NFPA 110: Standard for Emergency and Standby Power Systems, 2019 Edition, Section 110-17 7.9.5.** Integral tanks up to a maximum of 660 gallons for diesel fuel are permitted inside or on roofs of structures. https://www.nfpa.org/codes-and-standards/all-codes-and-standards/list-of-codes-and-standards/detail?code=110

Input	Default Value	Range	Source
			Some critical facilities such as hospitals are required to have 96 hours of fuel. Users can change the default depending on their building requirements. https://www.facilitiesnet.com/healthcarefacilities/article/NFPA-110s-Fuel-Requirements-Can-Help-Guide-Backup-Power-Plan-For-Hospitals--14338 For off-grid analyses, it is assumed that unlimited diesel fuel could be supplied to the site and stored properly. If fuel supply to the site is limited, the user should adjust this input.
Fixed O&M ($/kW/yr)	$10 general $20 Off-grid	$10-$35	**Lazard's Levelized Cost of Energy Analysis—Version 11.0. November 2017.** (NOTE: 2020 version doesn't include diesel analysis) https://www.lazard.com/media/450337/lazard-levelized-cost-of-energy-version-110.pdf For an output of 250-1000 kW, the Key Assumptions table lists a fixed O&M at $10/kW/yr. For a back-up generator, these costs are assumed to be small, primarily based on regular monthly maintenance. For off-grid analyses, the modeled generator is likely to run much more frequently, and the fixed O&M costs are estimated to be twice as high.
Variable O&M ($/kWh)	$0.00	$0.005 - $0.01	**Lazard's Levelized Cost of Energy Analysis—Version 11.0. November 2017.** (NOTE: 2020 version doesn't include diesel analysis) https://www.lazard.com/media/450337/lazard-levelized-cost-of-energy-version-110.pdf For an output of 250-1000 kW, the Key Assumptions table lists a variable O&M of $0.01/kWh. However, these cited costs are based on regular generator use. The generator modeled in the REopt web tool is a backup generator, with limited use, therefore the default for these costs is set to $0/kWh. The user can set a higher value if the generator will be used more extensively.
Fuel burn rate by generator capacity (gal/kWh)	0.076	0.069-0.172	**Generator Source Website: Approximate Diesel Fuel Consumption Chart.** February 2021 https://www.generatorsource.com/Diesel_Fuel_Consumption.aspx A constant specific fuel consumption rate default across generator sizes and load conditions is used due to fuel's relatively small percentage of the lifecycle cost for a generator used only as backup power in a grid outage and also due to the resulting significant positive impact on solution times. The median value across a size range of 20 kW to 2250 kW and a load range of 25% to 100% was selected as representative.

Input	Default Value	Range	Source
Fuel curve y-intercept by generator capacity (gal/hr)	0	0-0.71	Since a constant specific fuel consumption rate was chosen as the default across generator sizes and load conditions, the corresponding y-intercept value is assumed to be 0. The input field is retained to allow for custom y-intercept entries.
Minimum turndown (% of capacity	0% general 15% Off-grid		The default generator minimum turndown for off-grid analyses is 15% to limit the likelihood of infeasible solutions while avoiding unreasonable underloading. An N+1 generator capacity reserve is assumed by default, and thus a 15% minimum turndown equates to one of the two assumed generators running at 30% minimum turndown.
Generator replacement year	10 Off-grid		Generators typically run between 15,000 – 50,000 hours before requiring a major engine overhaul. If a generator were run for half the year, this would equate to a lifespan of 3.5-11.5 years, a quarter of the year would equate to 6.8-23 years. By default, REopt assumes a single replacement of the off-grid generator in year 10. Replacement cost is not considered for back-up generators in Resilience analyses. **ReactPower Solutions Website: The Life Expectancy of Your Diesel Generator.** Accessed 12/9/21. https://www.reactpower.com/blog/the-life-expectancy-of-your-diesel-generator/ General life expectancy: 15,000-50,000 hours **Worldwide Power Products Website: How Long Do Diesel Generators Last?** Accessed 12/9/21. https://www.wpowerproducts.com/news/diesel-engine-life-expectancy/ Approximate lifespan: 12,000-20,000 hours

Table 38. Combined Heat and Power Inputs, Default Values, Ranges, and Sources

Input	Default Value	Range	Source
Size Class			See default/reference in Section 14.8, 14.9, & Appendix A
Electric power capacity (kW)			See default/reference in Section 14.8, 14.9, & Appendix A
Install cost ($/kW)			See default/reference in Section 14.8, 14.9, & Appendix A
Fixed O&M cost ($/kW/yr)			See default/reference in Section 14.8, 14.9, & Appendix A
Variable O&M cost ($/kWh)			See default/reference in Section 14.8, 14.9, & Appendix A

Input	Default Value	Range	Source
Incentives	10% ITC for CHP 5 year MACRS 100% bonus depreciation		**Database of State Incentives for Renewables & Efficiency. NC Clean Energy Tech Center,accessed January 2022.** http://www.dsireusa.org/ Incentives are available at the federal, state, and local level. This site provides searchable specifics about incentives based on location. The following federal incentives are default values in the REopt web tool: **Business Energy Investment Tax Credit. Database of State Incentives for Renewables & Efficiency, NC Clean Energy Tech Center, February 2021.** https://programs.dsireusa.org/system/program/detail/658/business-energy-investment-tax-credit-itc In 2022, a federal 10% investment tax credit is available to CHP projects. **Modified Accelerated Cost-Recovery System. Database of State Incentives for Renewables & Efficiency, NC Clean Energy Tech Center, August 2018.** http://programs.dsireusa.org/system/program/detail/676 CHP projects are eligible for accelerated depreciation deductions over a 5-year period, with bonus depreciation of 100% in the first year.
CHP maintenance schedule			See default/reference in Section 14.10
Electric efficiency at 100% load (% HHV-basis)			See default/reference in Section 14.8 & Appendix A
Electric efficiency at 50% load (% HHV-basis)			See default/reference in Section 14.8
Thermal efficiency at 100% load (% HHV-basis			See default/reference in Section 14.8 & Appendix A
Thermal efficiency at 50% load (% HHV-basis)			See default/reference in Section 14.8
Min. electric loading of prime mover (% rated electric cap)			See default/reference in Section 14.8
Knockdown factor for CHP-supplied thermal to			See default/reference in Section 14.8 and Section 15

Input	Default Value	Range	Source
Absorption Chiller (%)			
Supplementary firing maximum steam production ratio			See default/reference in Section 14.5
Supplementary firing thermal efficiency (% HHV-basis)			See default/reference in Section 14.5
Installed Cost of Supplementary Firing ($/kW)			See default/reference in Section 14.5

Table 39. Hot Water Storage Inputs, Default Values, Ranges, and Sources

Input	Default Value	Range	Source
Install cost ($/kW)			See default/reference in Section 16
Fixed O&M cost ($/gal/yr)			See default/reference in Section 16
Thermal loss rate (%)			See default/reference in Section 16
Minimum state of charge (%)			See default/reference in Section 16

Table 40. Absorption Chilling Inputs, Default Values, Ranges, and Sources

Input	Default Value	Range	Source
Coefficient of performance (kWt/kWt)			See default/reference in Section 15
Electric consumption COP for heat rejection (kWt/kWe)			See default/reference in Section 15
Install cost ($/kW)			See default/reference in Section 15
Fixed O&M cost ($/ton/yr)			See default/reference in Section 15

Table 41. Chilled Water Storage Inputs, Default Values, Ranges, and Sources

Input	Default Value	Range	Source
Install cost ($/kW)			See default/reference in Section 16
Fixed O&M Cost ($/gal/yr)			See default/reference in Section 16
Thermal loss rate, percent of stored energy (%)			See default/reference in Section 16
Minimum state of charge (%)			See default/reference in Section 16

Table 42. Geothermal Heat Pump Inputs, Default Values, Ranges, and Sources

Input	Default Value	Range	Source
Installed cost heat pumps ($/ton)	$1075		RS Means 2018 for 5-ton unit
Installed cost GHX ($/ft)	$14	$7-$23	Liu, Xiaobing; Hughes, Patrick; McCabe, Kevin; et al.; "GeoVision Analysis Supporting Task Force Report: Thermal Applications - Geothermal Heat Pumps"; ORNL/TM-2019/502; April 2019 Default is the national average value.
Installed cost building interior water loop ($/ft^2)	$1.70		Liu, Xiaobing; Hughes, Patrick; McCabe, Kevin; et al.; "GeoVision Analysis Supporting Task Force Report: Thermal Applications - Geothermal Heat Pumps"; ORNL/TM-2019/502; April 2019
O&M cost ($/ft^2-yr)	-$0.51 (negative)		Liu, Xiaobing; Hughes, Patrick; McCabe, Kevin; et al.; "GeoVision Analysis Supporting Task Force Report: Thermal Applications - Geothermal Heat Pumps"; ORNL/TM-2019/502; April 2019

Input	Default Value	Range	Source
Incentives	10% ITC for CHP 5 year MACRS 100% bonus depreciation		**Database of State Incentives for Renewables & Efficiency. NC Clean Energy Tech Center, accessed January 2022.** http://www.dsireusa.org/ Incentives are available at the federal, state, and local level. This site provides searchable specifics about incentives based on location. The following federal incentives are default values in the REopt web tool: **Business Energy Investment Tax Credit. Database of State Incentives for Renewables & Efficiency, NC Clean Energy Tech Center, February 2021.** https://programs.dsireusa.org/system/program/detail/658/business-energy-investment-tax-credit-itc A federal 10% investment tax credit is available to GHP projects. **Modified Accelerated Cost-Recovery System. Database of State Incentives for Renewables & Efficiency, NC Clean Energy Tech Center, August 2018.** http://programs.dsireusa.org/system/program/detail/676 GHP projects are eligible for accelerated depreciation deductions over a 5-year period, with bonus depreciation of 100% in the first year.

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Appendix A: CHP Cost and Performance Data by Prime Mover Type and Size Class

The cost and performance data in Section 14.8, Topping Cycle Default CHP Cost & Performance Parameters by Prime Mover Type & Size Class, was generated by averaging the available data within the size class range from the DOE CHP Fact Sheets (DOE Advanced Manufacturing Office 2017). The following tables show the raw data and highlights the data that was averaged to get the size class cost and performance parameters. For fuel cells, the DOE CHP Fact Sheet data for phosphoric acid fuel cells (PAFC) and molten carbonate fuel cells (MCFC) was heavily modified by industry estimates.

Reciprocating Engine	System					
	1	2	3	4	5	6
Net Electric Power (kW)	35	100	633	1,141	3,325	9,341
Fuel Input (MMBtu/hr, HHV)	0.40	1.15	6.26	10.50	27.74	75.82
Useful Thermal, Hot Water (MMBtu/hr)	0.20	0.61	2.84	4.46	10.69	26.60
Cooling Thermal Factor (single effect)	80%	80%	85%	85%	85%	85%
Electric Efficiency (%, HHV)	29.6%	29.7%	34.5%	37.1%	40.9%	42.0%
Hot Water Thermal Efficiency (%, HHV)	49.5%	51.0%	44.8%	42.4%	38.5%	35.1%
Steam Thermal Efficiency (%, HHV)	N/A	N/A	18.2%	15.5%	13.3%	12.2%
O&M Cost ($/kWh)	$0.025	$0.024	$0.021	$0.019	$0.016	$0.009
Total Installed Cost ($/kW)	$3,300	$2,900	$2,700	$2,370	$1,800	$1,430
REopt Class 0						
REopt Class 1						
REopt Class 2						
REopt Class 3						
REopt Class 4						
REopt Class 5						

Microturbine	System					
	1	2	3	4	5	6
Net Electric Power (kW)	30	60	190	323	950	1,290
Fuel Input (MMBtu/hr, HHV)	0.43	0.84	2.29	3.84	11.43	15.02
Useful Thermal, Hot Water (MMBtu/hr)	0.21	0.39	0.90	1.45	4.30	5.65
Cooling Thermal Factor (single effect)	94%	94%	94%	94%	94%	94%
Electric Efficiency (%, HHV)	23.6%	24.4%	28.3%	28.7%	28.4%	29.3%
Hot Water Thermal Efficiency (%, HHV)	48.5%	46.2%	39.3%	37.8%	37.6%	37.6%
Steam Thermal Efficiency (%, HHV)	N/A	N/A	N/A	N/A	N/A	N/A
O&M Cost ($/kWh)	$0.026	$0.026	$0.016	$0.012	$0.012	$0.012
Total Installed Cost ($/kW)	$3,600	$3,220	$3,150	$2,580	$2,500	$2,400
REopt Class 0						
REopt Class 1						
REopt Class 2						
REopt Class 3						
REopt Class 4						
REopt Class 5						

Combustion Turbine	System						
	1 (1)	2	3	4	5	6	7
Net Electric Power (kW)	950	1,825	3,304	5,400	7,487	14,100	20,440
Fuel Input (MMBtu/hr, HHV)	15.4	27.6	47.5	68.2	87.6	160.4	210.8
Useful Thermal, Steam (MMBtu/hr)	6.7	13.5	19.6	29.8	36.3	64.5	77.4
Cooling Thermal Factor (double effect)	90%	90%	90%	90%	90%	90%	90%
Electric Efficiency (%, HHV)	21.0%	22.6%	23.7%	27.0%	29.2%	30.0%	33.1%
Steam Thermal Efficiency (%, HHV)	43.5%	48.9%	41.3%	43.7%	41.4%	40.2%	36.7%
Hot Water Thermal Efficiency (%, HHV)	47.5%	53.8%	45.8%	48.1%	45.5%	44.2%	40.8%
O&M Cost ($/kWh)	$0.015	$0.014	$0.013	$0.013	$0.012	$0.010	$0.009
Total Installed Cost ($/kW)	$4,480	$3,900	$3,320	$2,550	$2,017	$1,650	$1,474
REopt Class 0							
REopt Class 1							
REopt Class 2							
REopt Class 3							
REopt Class 4							
REopt Class 5							
REopt Class 6							

(1) 950 kW system is actually a microturbine system with 12% duct firing (4.01 MMBtu/hr fuel, 3.41 MMBtu/hr add'l steam)

Fuel Cell	System		
	1 (1)	2 (2)	3 (3)
Net Electric Power (kW)	440	1400	10000
Fuel Input (MMBtu/hr, HHV)	3.77	11.23	80.21
Useful Thermal, Hot Water (MMBtu/hr)	0.78	2.97	21.24
Cooling Thermal Factor (single effect)	85%	85%	85%
Electric Efficiency (%, HHV)	38.6%	41.3%	41.3%
Hot Water Thermal Efficiency (%, HHV)	20.6%	26.5%	26.5%
Steam Thermal Efficiency (%, HHV)	N/A	N/A	N/A
O&M Cost ($/kWh)	$0.036	$0.040	$0.040
Total Installed Cost ($/kW)	$5,000	$4,600	$3,680
REopt Class 0			
REopt Class 1			
REopt Class 2			

(1) This data represents PAFC

(2) This data represents MCFC

(3) This is an estimate for cost-scaling of larger installations

Back-pressure steam turbine performance data from the DOE CHP Fact Sheets:

Description	System		
	1	2	3
Net Electric Power (kW)	500	3,000	15,000
Fuel Input (MMBtu/hr, HHV)[4]	27.2	208.0	700.1
Steam Flow (lbs/hr)	20,050	152,600	494,464
Steam Inlet Pressure (psig)	500	600	700
Steam Inlet Temperature (°F)	550	575	650
Steam Outlet Pressure (psig)	50	150	150
Steam Outlet Temperature (°F)	298	373	380
Useful Thermal (MMBtu/hr)	20.0	155.5	506.8
Power to Heat Ratio[5]	0.086	0.066	0.101
Electric Efficiency (%, HHV)	6.3%	4.9%	7.3%
Thermal Efficiency (%, HHV)	73.3%	74.8%	72.4%
Overall Efficiency (%, HHV)	79.6%	79.7%	79.7%

Note: *Performance characteristics are average values and are not intended to represent a specific product.*

Back-pressure steam turbine cost data from the DOE CHP Fact Sheets:

Description	System		
	1	2	3
Net Electric Power (kW)	500	3,000	15,000
Steam Turbine and Generator ($/kW)	$668	$401	$392
Installation and Balance of Plant ($/kW, not including boiler and steam system)[6]	$468	$281	$274
Total Installed Cost ($/kW)	$1,136	$682	$666
O&M (¢/kWh, steam turbine and generator)	1.0	0.9	0.6

Appendix B: Efficiency Gain Potential of GHP Retrofit in Facilities with Variable-Air-Volume HVAC Equipment

This appendix describes the methodology used to estimate the excess heating and cooling associated with inefficient sub-cooling-and-reheat-based multi-zone VAV HVAC design that could be eliminated with GHP retrofit. This work is to approximate efficiency gains that may be available within facilities with VAV when retrofitted with distributed water-to-air heat pumps. See Section 17.5 for an introduction on this topic.

In VAV systems, multiple spaces are often served by one HVAC unit. Because of this, these systems can have inherent inefficiencies. Inefficiencies can occur when spaces served by a single central air handling unit have different levels of heating or cooling needs. When this occurs, the air supplied to the duct is cooled to meet the worst-case need. The following describes a scenario that results in excessive cooling and heating:

1. The central air handler supplies air to individual VAV boxes at a temperature suitable for space cooling.
2. When zones have different levels of cooling need, the dampers in the VAV box adjust the flowrate of conditioned air to match the zone's cooling requirement. A fully open damper provides the maximum amount of cooling to a zone. As less and less cooling is needed, the damper position adjusts down to a minimum stop position, which is typically specified to ensure adequate ventilation.
3. At a damper's minimum stop position, if space cooling sill exceeds the cooling needs of the zone, the zone will be cooled below the upper limit of the thermostat setting. Cooling below the thermostat upper limit is considered excessive because it is more than is needed to provide thermal comfort according to the definition of the space dead-band.

4. If the cooling provided at the minimum stop position were excessive to the point where the lower dead-band temperature limit of the thermostat is reached, the airstream is often ‘reheated’ at the VAV box to keep the zone above the thermostat’s lower temperature limit. At this point, excessive cooling is exacerbated by simultaneous heating to offset it.

Outside air, or ventilation air, is often mixed at the intake of the central HVAC unit and oftentimes this air needs to be dehumidified. Dehumidification is often done via subcooling to wring moisture until the desired humidity level is achieved. In our analysis, we assume subcooling for dehumidification is a requirement of the system, and therefore not excessive regardless of space conditioning requirements. Additionally, where reheat is needed at the zone level, the portion of that reheat needed to offset subcooling of ventilation air needed for dehumidification is also not considered excessive.

In this analysis:

1. We assume all cooling below the upper limit of the thermostat space temperature is excessive. This excessive cooling is considered an inefficiency that a GHP retrofit could eliminate.
2. We assume all reheat applied to offset over-cooling *beyond* what is needed to temper ventilation air that was sub-cooled for dehumidification is excessive. This additional reheat is considered an inefficiency that a GHP retrofit could eliminate.

An analysis was done to estimate HVAC inefficiencies in facilities with VAV HVAC systems using DOE Commercial Reference Buildings (CRB). EnergyPlus is used and accessed via OpenStudio. The following CRB reference building types contain multi-zone VAV systems with zone-level reheat and therefore have potential for efficiency gain with a GHP retrofit:

1. Large Office
2. Medium Office
3. Large Hotel
4. Primary School
5. Secondary School
6. Hospital
7. Outpatient Healthcare

The thermal loads to be served by the HVAC system include the heating and cooling needed for each conditioned space as well as the additional heating and cooling required for ventilation air. While the sensible zone-level heating and cooling thermal loads are provided directly from EnergyPlus, estimating the required versus excess cooling and heating at the building level is more involved.

Firstly, the conditioning needed for the ventilation air is inherently tied to the ventilation strategy used in the building. For more advanced systems, a dedicated outside air system (DOAS) could be employed to handle ventilation separate from space conditioning. Since this analysis leverages the reference building models, which do not contain DOAS, this analysis assumes no DOAS.

We also assume that the sub-cooling and reheat required for humidity control are required loads and that these loads too will need to be served by GHP. It is the excessive cooling beyond that needed for dehumidification and space conditioning that can occur in multi-zone VAV that is being estimated for elimination by GHP retrofit. In the application of the results in REopt, we currently assume reheat is hydronic and that the reheat load is within the facility entered gas heating loads. In a future update to REopt, accounting for electric reheat in the CRBs and the impact of eliminating inefficient reheat on the facility electric load will be included.

It is also assumed that the ventilation airstream needs to be cooled to 55°F to sufficiently dehumidify the building. This is a generic assumption that may or may not match what a system designer would specify. Seasonal resets are often employed to reduce excessive subcooling, however we do not consider seasonal resets in this analysis.

All heating and cooling done by multi-zone VAV systems with reheat was analyzed and corrected as necessary. Heating and cooling done by other air-loops are assumed to remain unchanged with GHP retrofit with the exception of CRB Hospital and Outpatient Healthcare. For these building types, load corrections were only done for multi-zone VAV systems serving non-critical zones. Healthcare HVAC systems (and the corresponding code requirements) are complex and the correction assumptions approach taken here are not fully applicable in those facilities. For healthcare facilities' HVAC systems serving critical zones, loads were assumed to be unchanged with GHP retrofit. This is likely a conservative approach since there is likely waste in those systems as well.

Details of Load Correction Calculations

Relevant quantities were calculated as follows:

- **Reheat.** Not all heating done at the zone terminals is reheat. Heating is only reheat when it is canceling out mechanical cooling (i.e., mechanical cooling is done at the AHU to cool the mixed air stream to 55°F, and the portion of that air stream delivered to a zone is reheated to maintain the zone heating setpoint). Reheat is calculated as the amount of zone terminal heating needed to cancel out the net sensible cooling done by the AHU chilled water coils (coil sensible cooling load – fan heat).
- **Credited reheat.** This is the reheat needed to cancel out the sub-cooling required to dehumidify the ventilation air. This is the smaller between the actual reheat energy and the amount of heating needed to balance the net sensible ventilation cooling load (sensible ventilation cooling – fan power for AHUs in cooling mode).
- **Excess reheat.** This is reheat above which is needed to cancel out the net sub-cooling required to dehumidify the ventilation air. In most cases this makes up a small percentage of total reheat.
- **Excess AHU heat.** This is applicable only in cases where simultaneous cooling and heating are done at the central air handler. Realistically, this should only happen for these system types if there is a control logic issue. As such, this should be zero or very close to zero for all cases.
- **Total ventilation cooling load.** The total cooling load (including the latent load) required to cooling the outdoor air stream to 55°F. This is based on the enthalpy difference between outdoor air at current conditions when that air is cooled to 55°F (which may or may not

achieve a saturated condition). Mass flow rate is taken directly from the EnergyPlus simulation.

- **Sensible ventilation cooling load.** Similar to above but just the sensible component (calculated based on the temperature difference).
- **Latent ventilation cooling load.** The difference between the total and sensible loads.
- **Sensible cooling provided by outdoor air.** When the ventilation air is cooled to 55°F, the resulting sensible cooling can meet all or most of the zone cooling load most of the time. When outdoor air is colder than 55°F, this load is based on the temperature difference between the AHU return air stream and the outdoor air (and the mass flow is the outdoor air flow rate). When outdoor air is warmer than 55°F, this load is based on the temperature difference between AHU return air stream and 55°F (and the mass flow is the outdoor air flow rate).
- **Excess total cooling.** This is calculated as total cooling minus the total ventilation cooling load, the fan power of AHUs in cooling mode, and any excess zone cooling load above the sensible cooling provided by the ventilation load.
- **Corrected Heating Demand – Excess Reheat and AHU Heat Removed.** This is the total heating load for the building minus excess reheat and any excess AHU heat. This is the heating load to be passed to the GHP model.
- **Corrected Total Cooling Demand - Excess Removed.** This is the total cooling load for the building minus excess total cooling. This is the total cooling load to be passed to the GHP model.

Analysis Findings

The results of the analysis are summarized in the tables below. Note that the defaults in REopt are currently using the results from the 1989 ASHRAE 90.1 code shown in Table 43. The results in Table 44 are included for reference.

Table 43. Default thermal correction factors in percentage (%) by climate zone and building type (ASHRAE 90.1 1989)

Building Type	Thermal Load	1A	2A	2B	3A	3B	3C	4A	4B	4C	5A	5B	6A	6B	7A	8A
Large Office	Heating	63	33	62	65	83	49	73	94	91	97	97	98	97	98	99
	Cooling	50	50	40	46	39	34	44	38	33	38	38	38	36	36	31
Medium Office	Heating	70	55	58	81	78	46	88	92	88	97	96	98	97	98	99
	Cooling	67	63	59	59	55	43	57	56	38	49	56	49	50	46	40
Primary School	Heating	87	93	78	98	88	76	99	95	94	98	97	99	98	99	99
	Cooling	88	88	79	85	74	63	85	72	58	72	75	73	72	72	64
Secondary School	Heating	93	97	88	99	95	88	100	98	98	99	99	99	98	99	99
	Cooling	92	92	88	90	86	75	90	86	75	79	83	76	76	71	59
Hospital	Heating	76	65	66	62	72	62	67	79	82	85	84	87	88	89	93
	Cooling	74	73	68	69	68	63	69	71	70	70	73	70	74	71	73
Outpatient	Heating	99	89	83	86	87	79	71	89	88	92	92	94	94	95	97
	Cooling	84	85	77	81	77	70	69	76	73	74	77	75	76	75	73
Large Hotel	Heating	100	93	84	95	91	84	98	95	95	99	97	99	98	99	99
	Cooling	91	92	87	87	83	81	88	80	82	85	79	82	81	80	77

Table 44. Thermal correction factors in percentage (%) by climate zone and building type for ASHRAE 90.1 2007.

Building Type	Thermal Load	1A	2A	2B	3A	3B	3C	4A	4B	4C	5A	5B	6A	6B	7A	8A
Large Office	Heating	99	76	81	94	96	79	81	98	96	99	99	100	99	100	100
	Cooling	77	79	64	78	66	66	67	67	73	73	70	73	74	75	79
Medium Office	Heating	99	63	76	89	95	77	86	98	96	99	99	99	99	100	100
	Cooling	75	75	62	70	59	48	56	55	41	52	56	53	52	52	45
Primary School	Heating	96	98	93	99	99	74	100	100	98	99	100	100	100	100	100
	Cooling	95	97	84	94	83	75	93	81	73	81	83	81	81	81	80
Secondary School	Heating	100	95	86	98	94	73	99	98	96	99	99	99	99	99	100
	Cooling	94	95	91	94	90	86	94	91	88	89	91	88	92	89	92
Hospital	Heating	100	99	95	99	95	93	82	97	97	98	98	98	99	99	99
	Cooling	95	95	92	94	92	81	84	92	87	88	93	89	91	89	90
Outpatient	Heating	99	89	83	86	87	79	71	89	88	92	92	94	94	95	97
	Cooling	84	85	77	81	77	70	69	76	73	74	77	75	76	75	73
Large Hotel	Heating	98	90	91	94	96	80	96	97	94	98	99	99	99	99	99
	Cooling	72	74	73	67	69	46	65	69	41	56	68	59	60	55	43

1 Appendix C: Mathematical Formulation

We define, in alphabetic order within a group, indices and sets, parameters, and variables, in that order, and then state the objective function and the constraints. We choose as our naming convention calligraphic capital letters to represent sets, lower-case letters to represent parameters, and upper-case letters to represent variables; in the latter case, Z-variables are binary. X-variables represent continuous decisions, e.g., quantities of energy. All subscripts denote indices. Names with the same "stem" are related, and superscripts and "decorations" (e.g., hats, tildes) differentiate the names with respect to, e.g., various indices included in the name or maximum and minimum values for the same parameter.

1.1 Sets and Parameters

Sets	
$\mathcal{B}$	Storage systems
$\mathcal{C}$	Technology classes
$\mathcal{D}$	Time-of-use demand periods
$\mathcal{E}$	Electrical time-of-use demand tiers
$\mathcal{F}$	Fuel types
$\mathcal{H}$	Time steps
$\mathcal{K}$	Subdivisions of power rating
$\mathcal{M}$	Months of the year
$\mathcal{N}$	Monthly peak demand tiers
$\mathcal{P}$	Pollutant types
$\mathcal{P}^{\text{r}} \subseteq \mathcal{P}$	Pollutant types with emissions reduction targets
$\mathcal{S}$	Power rating segments
$\mathcal{T}$	Technologies
$\mathcal{U}$	Total electrical energy pricing tiers
$\mathcal{V}$	Net metering regimes

Subsets and Indexed Sets	
$\mathcal{B}^{\text{c}} \subseteq \mathcal{B}^{\text{th}}$	Cold thermal energy storage systems
$\mathcal{B}^{\text{e}} \subseteq \mathcal{B}$	Electrical storage systems
$\mathcal{B}^{\text{h}} \subseteq \mathcal{B}^{\text{th}}$	Hot thermal energy storage systems
$\mathcal{B}^{\text{th}} \subseteq \mathcal{B}$	Thermal energy storage systems
$\mathcal{H}^{\text{g}} \subseteq \mathcal{H}$	Time steps in which grid purchasing is available
$\mathcal{H}_m \subseteq \mathcal{H}$	Time steps within a given month m
$\mathcal{H}_d \subseteq \mathcal{H}$	Time steps within electrical power time-of-use demand tier d
$\mathcal{K}_t \subseteq \mathcal{K}$	Subdivisions applied to technology t
$\mathcal{K}^{\text{c}} \subseteq \mathcal{K}$	Capital cost subdivisions
$\mathcal{M}^{\text{lb}}$	Look-back months considered for peak pricing
$\mathcal{S}_{tk} \subseteq \mathcal{S}$	Power rating segments from subdivision k applied to technology t

$\mathcal{T}_b \subseteq \mathcal{T}$	Technologies that can charge storage system b
$\mathcal{T}_c \subseteq \mathcal{T}$	Technologies in class c
$\mathcal{T}_f \subseteq \mathcal{T}$	Technologies that burn fuel type f
$\mathcal{T}_u \subseteq \mathcal{T}$	Technologies that may access energy sales pricing tier u
$\mathcal{T}_v \subseteq \mathcal{T}$	Technologies that may access net-metering regime v
$\mathcal{T}^{\mathrm{ac}} \subseteq \mathcal{T}^{\mathrm{cl}}$	Absorption chillers
$\mathcal{T}^{\mathrm{CHP}} \subseteq \mathcal{T}^{\mathrm{f}}$	CHP technologies
$\mathcal{T}^{\mathrm{cl}} \subseteq \mathcal{T}$	Cooling technologies
$\mathcal{T}^{\mathrm{e}} \subseteq \mathcal{T}$	Electricity-producing technologies
$\mathcal{T}^{\mathrm{ec}} \subseteq \mathcal{T}^{\mathrm{cl}}$	Electric chillers
$\mathcal{T}^{\mathrm{f}} \subseteq \mathcal{T}^{\mathrm{e}}$	Fuel-burning, electricity-producing technologies
$\mathcal{T}^{\mathrm{ht}} \subseteq \mathcal{T}$	Heating technologies
$\mathcal{T}^{\mathrm{s}} \subseteq \mathcal{T}$	Technologies that can provide operating reserves
$\mathcal{T}^{\mathrm{td}} \subseteq \mathcal{T}$	Technologies that cannot turn down, i.e., PV and wind
$\mathcal{U}^{\mathrm{nm}} \subseteq \mathcal{U}^{s}$	Electrical energy sales pricing tiers used in net metering
$\mathcal{U}^{\mathrm{p}} \subseteq \mathcal{U}$	Electrical energy purchase pricing tiers
$\mathcal{U}^{\mathrm{s}} \subseteq \mathcal{U}$	Electrical energy sales pricing tiers
$\mathcal{U}^{\mathrm{s}}_t \subseteq \mathcal{U}^{\mathrm{s}}$	Electrical energy sales pricing tiers accessible by technology t
$\mathcal{U}^{\mathrm{sb}} \subseteq \mathcal{U}^{\mathrm{s}}$	Electrical energy sales pricing tiers accessible by storage

Scaling Parameters

Γ	Number of time periods within a day	[-]
Δ	Time step scaling	[h]
Θ	Peak load oversizing factor	[-]
M	Sufficiently large number	[various]

Parameters for Costs and their Functional Forms

c^{afc}	Utility annual fixed charge	[$]
c^{amc}	Utility annual minimum charge	[$]
c^{cb}_{ts}	y-intercept of capital cost curve for technology t in segment s	[$]
c^{cm}_{ts}	Slope of capital cost curve for technology t in segment s	[$/kW]
c^{e}_{uh}	Export rate for energy in energy demand tier u in time step h	[$/kWh]
c^{g}_{uh}	Grid energy cost in energy demand tier u during time step h	[$/kWh]
c^{f}_{p}	Marginal cost of emissions for pollutant p related to on-site fuel burn in the first year	[$/ton]
$\bar{c}^{\mathrm{g}}_{p}$	Marginal cost of emissions for pollutant p related to grid-purchased electricity in the first year	[$/ton]
c^{kW}_{b}	Capital cost of power capacity for storage system b	[$/kW]
c^{kWh}_{b}	Capital cost of energy capacity for storage system b	[$/kWh]
c^{omb}_{b}	Operation and maintenance cost of storage system b per unit of energy rating	[$/kWh]
c^{omp}_{t}	Operation and maintenance cost of technology t per unit of production	[$/kWh]
$c^{\mathrm{om}\sigma}_{t}$	Operation and maintenance cost of technology t per unit of power rating, including standby charges	[$/kW]
c^{r}_{de}	Cost per unit peak demand in time-of-use demand period d and tier e	[$/kW]

c^{rm}_{mn}	Cost per unit peak demand in tier n during month m	[$/kW]
c^{u}_{f}	Unit cost of fuel type f	[$/MMBTU]

Demand Parameters

δ^{c}_{h}	Cooling load in time step h	[kW]
δ^{d}_{h}	Electrical load in time step h	[kW]
$\bar{\delta}^{\mathrm{gs}}_{u}$	Maximum allowable sales in electrical energy demand tier u	[kWh]
δ^{h}_{h}	Heating load in time step h	[kW]
δ^{lp}	Look-back proportion for ratchet charges	[fraction]
$\bar{\delta}^{\mathrm{mt}}_{n}$	Maximum monthly electrical power demand in peak pricing tier n	[kW]
$\bar{\delta}^{\mathrm{t}}_{e}$	Maximum power demand in time-of-use demand tier e	[kW]
$\bar{\delta}^{\mathrm{tu}}_{u}$	Maximum monthly electrical energy demand in tier u	[kWh]
$\underline{\delta}^{\mathrm{an}}$	Minimum annual load that must be met	[%]
θ^{ℓ}_{h}	Load operating reserve requirement in time step h	[%]
θ^{pv}_{h}	PV operating reserve requirement in time step h	[%]

Incentive Parameters

$\bar{\imath}_{t}$	Upper incentive limit for technology t	[$]
i^{n}_{v}	Net metering limits in net metering regime v	[kW]
i^{r}_{t}	Incentive rate for technology t	[$/kWh]
$\bar{\imath}^{\sigma}_{t}$	Maximum power rating for obtaining production incentive for technology t	[kW]

Technology-Specific Time-Series Factor Parameters

f^{ed}_{th}	Electrical power de-rate factor of technology t at time step h	[unitless]
f^{fa}_{th}	Fuel burn ambient correction factor of technology t at time step h	[unitless]
f^{ha}_{th}	Hot water ambient correction factor of technology t at time step h	[unitless]
f^{ht}_{th}	Hot water thermal grade correction factor of technology t at time step h	[unitless]
f^{p}_{th}	Production factor of technology t during time step h	[unitless]

Technology-Specific Factor Parameters

f^{d}_{t}	Derate factor for turbine technology t	[unitless]
f^{l}_{t}	Levelization factor of technology t	[fraction]
f^{li}_{t}	Levelization factor of production incentive for technology t	[fraction]
f^{pf}_{t}	Present worth factor for fuel for technology t	[unitless]
f^{pi}_{t}	Present worth factor for incentives for technology t	[unitless]
$\underline{f}^{\mathrm{td}}_{t}$	Minimum turn down for technology t	[unitless]

Pollutant and Generic Factor Parameters

e^{f}_{pt}	Fuel emissions rate of pollutant p by technology t	[ton/MMBTU]
e^{g}_{ph}	Grid emissions rate of pollutant p in time step h	[ton/kWh]
f^{e}	Energy present worth factor	[unitless]

f_p^{fc}	Present worth factor for fuel emissions costs related to pollutant p	[unitless]
f_p^{gc}	Present worth factor for grid emissions costs related to pollutant type p	[unitless]
f_p^{fe}	Present worth factor for fuel emissions related to pollutant p	[unitless]
f_p^{ge}	Present worth factor for grid emissions related to pollutant type p	[unitless]
f^{om}	Operations and maintenance present worth factor	[unitless]
f^{tot}	Tax rate factor for off-taker	[fraction]
f^{tow}	Tax rate factor for owner	[fraction]
f_t^{re}	Proportion of renewable electricity produced by technology t	[fraction]
f_t^{rh}	Proportion of renewable heat production from technology t	[fraction]
$\underline{b}_p^{\mathrm{e}}$	Minimum allowable lifecycle emissions of pollutant p	[ton]
$\bar{b}_p^{\mathrm{e}}$	Maximum allowable lifecycle emissions of pollutant p	[ton]
$\underline{b}^{\mathrm{re}}$	Minimum allowable proportion of renewable electricity production	[fraction]
$\bar{b}^{\mathrm{re}}$	Maximum allowable proportion of renewable electricity production	[fraction]
$\underline{b}^{\mathrm{rh}}$	Minimum allowable proportion of renewable heat production	[fraction]
$\bar{b}^{\mathrm{rh}}$	Maximum allowable proportion of renewable heat production	[fraction]

Power Rating and Fuel Limit Parameters

b_f^{fa}	Amount of available fuel for fuel type f	[MMBTU]
b_{th}^{p}	Total production potential for technology t in time step h	[kW]
$\underline{b}_c^{\sigma}$	Minimum power rating for technology class c	[kW]
$\bar{b}_t^{\sigma}$	Maximum power rating for technology t	[kW]
$\underline{b}_{tks}^{\sigma\mathrm{s}}$	Minimum power rating for technology t applied to subdivision k, segment s	[kW]
$\bar{b}_{tks}^{\sigma\mathrm{s}}$	Maximum power rating for technology t applied to subdivision k, segment s	[kW]

Efficiency Parameters

η_{bt}^{+}	Efficiency of charging storage system b using technology t	[fraction]
η_b^{-}	Efficiency of discharging storage system b	[fraction]
η^{ac}	Absorption chiller efficiency	[fraction]
$\eta^{\mathrm{ac\text{-}e}}$	Absorption chiller electrical efficiency	[fraction]
η^{b}	Boiler efficiency	[fraction]
η^{ec}	Electric chiller efficiency	[fraction]
$\eta^{\mathrm{g+}}$	Efficiency of charging electrical storage using grid power	[fraction]

Storage Parameters

$\bar{w}_b^{\mathrm{bkW}}$	Maximum power output of storage system b	[kW]
$\underline{w}_b^{\mathrm{bkW}}$	Minimum power output of storage system b	[kW]
$\bar{w}_b^{\mathrm{bkWh}}$	Maximum energy capacity of storage system b	[kWh]
$\underline{w}_b^{\mathrm{bkWh}}$	Minimum energy capacity of storage system b	[kWh]
w_b^{d}	Decay rate of storage system b	[1/h]
$\underline{w}_b^{\mathrm{mcp}}$	Minimum percent state of charge of storage system b	[fraction]

w_b^0	Initial percent state of charge of storage system b	[fraction]

Fuel Burn Parameters

m_t^{fb}	y-intercept of the fuel rate curve for technology t	[MMBTU/h]
m_t^{fbm}	Fuel burn rate y-intercept per unit size for technology t	[MMBTU/kWh]
m_t^{fm}	Slope of the fuel rate curve for technology t	[MMBTU/kWh]

CHP Thermal Performance Parameters

k_t^{te}	Thermal energy production of CHP technology t per unit electrical output	[unitless]
k_t^{tp}	Thermal power production of CHP technology t per unit power rating	[unitless]

1.2 Variables

Boundary Conditions

$X_{b,0}^{\text{se}}$	Initial state of charge for storage system b	[kWh]

Continuous Variables

$X_h^{\text{ar-b}}$	Available operating reserves from excess battery capacity in time step h	[kW]
X_{th}^{ar}	Available operating reserves from technology t in time step h	[kW]
X_b^{bkW}	Power rating for storage system b	[kW]
X_b^{bkWh}	Energy rating for storage system b	[kWh]
X_{de}^{de}	Peak electrical power demand allocated to tier e and time-of-use demand period d	[kW]
X_{bh}^{dfs}	Power discharged from storage system b during time step h	[kW]
X_{mn}^{dn}	Peak electrical power demand allocated to tier n in month m	[kW]
X_h^{e}	Proportion of electrical load served in time step h	[%]
X_{th}^{f}	Fuel burned by technology t in time step h	[MMBTU/h]
X_{th}^{fb}	y-intercept of fuel burned by technology t in time step h	[MMBTU/h]
X_{uh}^{g}	Power purchased from the grid for electrical load in demand tier u during time step h	[kW]
X_h^{gts}	Electrical power from the grid used to charge storage in time step h	[kW]
X_{th}^{ℓ}	Production from technology $t \in \mathcal{T}^s$ serving load in time step h	[kW]
X^{mc}	Annual utility minimum charge adder	[$]
X_t^{pi}	Production incentive collected for technology t	[$]
X^{plb}	Peak electrical demand during look-back periods	[kW]
X_{tuh}^{ptg}	Exports from production to the grid by technology t in demand tier u during time step h	[kW]
X_{bth}^{pts}	Power from technology t used to charge storage system b during time step h	[kW]
X_{th}^{ptw}	Thermal power from technology t sent to waste or curtailed during time step h	[kW]
X_{th}^{ptc}	Electrical power from technology t curtailed in time step h	[kW]

X_h^{r}	Total operating reserves requirement in time step h	[kW]
X_{th}^{rp}	Rated production of technology t during time step h	[kW]
X_t^{σ}	Power rating of technology t	[kW]
$X_{tks}^{\sigma\mathrm{s}}$	Power rating of technology t allocated to subdivision k, segment s	[kW]
X_{bh}^{se}	State of charge of storage system b at the end of time step h	[kWh]
X_{uh}^{stg}	Exports from storage to the grid in demand tier u during time step h	[kW]
X_{th}^{tp}	Thermal production of technology t in time step h	[kW]
X_{th}^{tpb}	y-intercept of thermal production of CHP technology t in time step h	[kW]

Binary Variables

Z_{mn}^{dmt}	1 If tier n has allocated demand during month m; 0 otherwise	[unitless]
Z_{de}^{dt}	1 if tier e has allocated demand during time-of-use period d; 0 otherwise	[unitless]
Z_v^{nmil}	1 If generation is in net metering interconnect limit regime v; 0 otherwise	[unitless]
Z_t^{pi}	1 If production incentive is available for technology t; 0 otherwise	[unitless]
$Z_{tks}^{\sigma\mathrm{s}}$	1 If technology t in subdivision k, segment s is chosen; 0 otherwise	[unitless]
Z_{th}^{to}	1 If technology t is operating in time step h; 0 otherwise	[unitless]
Z_{mu}^{ut}	1 If demand tier u is active in month m; 0 otherwise	[unitless]

1.3 Objective Function

$$
\begin{aligned}
(\widehat{\mathcal{R}}) \quad \text{minimize} \quad & \underbrace{\sum_{t\in\mathcal{T},k\in\mathcal{K}^{\mathrm{c}},s\in\mathcal{S}_{tk}} \left(c^{\mathrm{cm}}_{ts} \cdot X^{\sigma\mathrm{s}}_{tks} + c^{\mathrm{cb}}_{ts} \cdot Z^{\sigma\mathrm{s}}_{tks} \right)}_{\text{Generating Technology Capital Costs}} + \\
& \underbrace{\sum_{b\in\mathcal{B}} \left(c^{\mathrm{kW}}_{b} \cdot X^{\mathrm{bkW}}_{b} + (c^{\mathrm{kWh}}_{b} + c^{\mathrm{omb}}_{b}) \cdot X^{\mathrm{bkWh}}_{b} \right)}_{\text{Storage Capital Costs}} + \\
& (1-f^{\mathrm{tow}}) \cdot f^{\mathrm{om}} \cdot \left(\underbrace{\sum_{t\in\mathcal{T}} c^{\mathrm{om}\sigma}_{t} \cdot X^{\sigma}_{t}}_{\text{Fixed O\&M Costs}} + \underbrace{\sum_{t\in\mathcal{T}^{\mathrm{f}},h\in\mathcal{H}} c^{\mathrm{omp}}_{t} \cdot X^{\mathrm{rp}}_{th}}_{\text{Variable O\&M Costs}} \right) + \\
& (1-f^{\mathrm{tot}}) \cdot \Delta \cdot \underbrace{\sum_{f\in\mathcal{F}} c^{\mathrm{u}}_{f} \cdot \sum_{t\in\mathcal{T}_f,h\in\mathcal{H}} f^{\mathrm{pf}}_{t} \cdot X^{\mathrm{f}}_{th}}_{\text{Fuel Charges}} + \\
& (1-f^{\mathrm{tot}}) \cdot f^{\mathrm{e}} \cdot \Bigg(\underbrace{\Delta \cdot \sum_{u\in\mathcal{U}^{\mathrm{p}},h\in\mathcal{H}^{\mathrm{g}}} c^{\mathrm{g}}_{uh} \cdot X^{\mathrm{g}}_{uh}}_{\text{Grid Energy Charges}} + \\
& \underbrace{\sum_{d\in\mathcal{D},e\in\mathcal{E}} c^{\mathrm{r}}_{de} \cdot X^{\mathrm{de}}_{de}}_{\text{Time-of-Use Demand Charges}} + \underbrace{\sum_{m\in\mathcal{M},n\in\mathcal{N}} c^{\mathrm{rm}}_{mn} \cdot X^{\mathrm{dn}}_{mn}}_{\text{Monthly Demand Charges}} + \\
& \underbrace{c^{\mathrm{afc}} + X^{\mathrm{mc}}}_{\text{Fixed Charges}} - \\
& \underbrace{\Delta \cdot \left(\sum_{h\in\mathcal{H}^{\mathrm{g}}} \left(\sum_{u\in\mathcal{U}^{\mathrm{sb}}} c^{\mathrm{e}}_{uh} \cdot X^{\mathrm{stg}}_{uh} + \sum_{t\in\mathcal{T},u\in\mathcal{U}^{\mathrm{s}}_{t}} c^{\mathrm{e}}_{uh} \cdot X^{\mathrm{ptg}}_{tuh} \right) \right)}_{\text{Energy Export Payment}} \Bigg) - \\
& (1-f^{\mathrm{tow}}) \cdot \underbrace{\sum_{t\in\mathcal{T}} X^{\mathrm{pi}}_{t}}_{\text{Production Incentives}} + \\
& \underbrace{\sum_{p\in\mathcal{P}} f^{\mathrm{f}}_{p} \cdot c^{\mathrm{f}}_{p} \sum_{t\in\mathcal{T}^{\mathrm{f}},h\in\mathcal{H}} \Delta \cdot e^{\mathrm{fc}}_{pt} \cdot X^{\mathrm{f}}_{th} + \sum_{p\in\mathcal{P}} f^{\mathrm{gc}}_{p} \cdot \bar{c}^{\mathrm{g}}_{p} \sum_{h\in\mathcal{H},u\in\mathcal{U}} \Delta \cdot e^{\mathrm{g}}_{ph} \cdot X^{\mathrm{g}}_{uh}}_{\text{Emissions Costs}}
\end{aligned}
$$

The objective function minimizes energy life cycle cost, i.e., capital costs, O&M costs, utility costs, and emissions costs; it maximizes (by subtracting) payments for energy exports and other incentives.

1.4 Constraints

1.4.1 Fuel constraints

$$
\Delta \cdot \sum_{t\in\mathcal{T}_f,h\in\mathcal{H}} X^{\mathrm{f}}_{th} \leq b^{\mathrm{fa}}_{f} \quad \forall f \in \mathcal{F} \tag{1a}
$$

$$X^{\mathrm{f}}_{th} = m^{\mathrm{fm}}_{t} \cdot f^{\mathrm{p}}_{th} \cdot X^{\mathrm{rp}}_{th} + m^{\mathrm{fb}}_{t} \cdot Z^{\mathrm{to}}_{th} \quad \forall t \in \mathcal{T}^{\mathrm{f}} \backslash \mathcal{T}^{\mathrm{CHP}}, h \in \mathcal{H} \tag{1b}$$

$$X^{\mathrm{f}}_{th} = m^{\mathrm{fm}}_{t} \cdot X^{\mathrm{tp}}_{th} \quad \forall t \in \mathcal{T}^{\mathrm{ht}} \setminus \mathcal{T}^{CHP},\ h \in \mathcal{H} \tag{1c}$$

$$X^{\mathrm{f}}_{th} = f^{\mathrm{fa}}_{th} \cdot \left(X^{\mathrm{fb}}_{th} + f^{\mathrm{p}}_{th} \cdot m^{\mathrm{fm}}_{t} \cdot X^{\mathrm{rp}}_{th} \right) \quad \forall t \in \mathcal{T}^{CHP}, h \in \mathcal{H} \tag{1d}$$

$$m^{\mathrm{fbm}}_{t} \cdot X^{\sigma}_{t} - M \cdot (1 - Z^{\mathrm{to}}_{th}) \leq X^{\mathrm{fb}}_{th} \quad \forall t \in \mathcal{T}^{\mathrm{CHP}}, h \in \mathcal{H} \tag{1e}$$

Constraint (1a) limits fuel consumption for each fuel type, which can be burned by different technologies. Constraint (1b) uses a linear function to relate a non-CHP, fuel-burning electricity-producing technology's output to the corresponding consumption. Constraint (1c) defines the fuel burn of each non-CHP heating technology as directly proportional to its thermal production in each hour. Constraint (1d) defines fuel consumption using a size-dependent y-intercept and fixed slope, for every CHP technology and hour. Constraint (1e) limits the y-intercept of fuel burned by a CHP technology in a given time step based on the power rating of the technology as long as the technology is operating, and is void otherwise.

1.4.2 Thermal production constraints

$$X^{\mathrm{tpb}}_{th} \leq \min \left\{ k^{\mathrm{tp}}_{t} \cdot X^{\sigma}_{t}, M \cdot Z^{\mathrm{to}}_{th} \right\} \quad \forall t \in \mathcal{T}^{\mathrm{CHP}}, h \in \mathcal{H} \tag{2a}$$

$$X^{\mathrm{tpb}}_{th} \geq k^{\mathrm{tp}}_{t} \cdot X^{\sigma}_{t} - M \cdot (1 - Z^{\mathrm{to}}_{th}) \quad \forall t \in \mathcal{T}^{\mathrm{CHP}}, h \in \mathcal{H} \tag{2b}$$

$$f^{\mathrm{ha}}_{th} \cdot f^{\mathrm{ht}}_{th} \cdot \left(k^{\mathrm{te}}_{t} \cdot f^{\mathrm{p}}_{th} \cdot X^{\mathrm{rp}}_{th} + X^{\mathrm{tpb}}_{th} \right) = X^{\mathrm{tp}}_{th} \quad \forall t \in \mathcal{T}^{\mathrm{CHP}}, h \in \mathcal{H} \tag{2c}$$

Constraints (2a)-(2b) limit the fixed component of thermal production of CHP technology t in time step h to the product of the thermal power production per unit of power rating and the power rating itself if the technology is operating, and 0 if it is not. Constraint (2c) relates the thermal production of a CHP technology to its constituent components, where the relationship includes a term that is proportional to electrical power production in each time step.

1.4.3 Storage System Constraints

Boundary Conditions and Size Limits

$$X^{\mathrm{se}}_{b,0} = w^{0}_{b} \cdot X^{\mathrm{bkWh}}_{b} \quad \forall b \in \mathcal{B} \tag{3a}$$

$$\underline{w}^{\mathrm{bkWh}}_{b} \leq X^{\mathrm{bkWh}}_{b} \leq \bar{w}^{\mathrm{bkWh}}_{b} \quad \forall b \in \mathcal{B} \tag{3b}$$

$$\underline{w}^{\mathrm{bkW}}_{b} \leq X^{\mathrm{bkW}}_{b} \leq \bar{w}^{\mathrm{bkW}}_{b} \quad \forall b \in \mathcal{B} \tag{3c}$$

Constraint (3a) initializes a storage system's state of charge using a fraction of its energy rating; constraints (3b) - (3c) limit the storage system size under the implicit assumption that a storage system's power and energy ratings are independent. These constraints are identical to those given in ($\mathcal{R}$), but work in conjunction with significantly modified storage constraints that directly follow.

Storage Operations

$$X^{\mathrm{pts}}_{bth} + \sum_{u \in \mathcal{U}^{\mathrm{s}}_{t}} X^{\mathrm{ptg}}_{tuh} \leq f^{\mathrm{p}}_{th} \cdot f^{\mathrm{l}}_{t} \cdot X^{\mathrm{rp}}_{th} \quad \forall b \in \mathcal{B}^{\mathrm{e}},\ t \in \mathcal{T}^{\mathrm{e}},\ h \in \mathcal{H}^{\mathrm{g}} \tag{3d}$$

$$X^{\mathrm{pts}}_{bth} \leq f^{\mathrm{p}}_{th} \cdot f^{\mathrm{l}}_{t} \cdot X^{\mathrm{rp}}_{th} \quad \forall b \in \mathcal{B}^{\mathrm{e}},\ t \in \mathcal{T}^{\mathrm{e}},\ h \in \mathcal{H} \setminus \mathcal{H}^{\mathrm{g}} \tag{3e}$$

$$X^{\mathrm{pts}}_{bth} \leq f^{\mathrm{p}}_{th} \cdot X^{\mathrm{tp}}_{th} \quad \forall b \in \mathcal{B}^{\mathrm{th}},\ t \in \mathcal{T}_{b} \setminus \mathcal{T}^{\mathrm{CHP}},\ h \in \mathcal{H} \tag{3f}$$

$$X^{\text{pts}}_{bth} + X^{\text{ptw}}_{th} \leq X^{\text{tp}}_{th} \quad \forall b \in \mathcal{B}^{\text{h}},\ t \in \mathcal{T}^{\text{CHP}},\ h \in \mathcal{H} \tag{3g}$$

$$X^{\text{se}}_{bh} = X^{\text{se}}_{b,h-1} + \Delta \cdot \left(\sum_{t \in \mathcal{T}^{\text{e}}} (\eta^{+}_{bt} \cdot X^{\text{pts}}_{bth}) + \eta^{\text{g}+} \cdot X^{\text{gts}}_{h} - X^{\text{dfs}}_{bh} / \eta^{-}_{b} \right) \quad \forall b \in \mathcal{B}^{\text{e}},\ h \in \mathcal{H}^{\text{g}} \tag{3h}$$

$$X^{\text{se}}_{bh} = X^{\text{se}}_{b,h-1} + \Delta \cdot \left(\sum_{t \in \mathcal{T}^{\text{e}}} (\eta^{+}_{bt} \cdot X^{\text{pts}}_{bth}) - X^{\text{dfs}}_{bh} / \eta^{-}_{b} \right) \quad \forall b \in \mathcal{B}^{\text{e}},\ h \in \mathcal{H} \setminus \mathcal{H}^{\text{g}} \tag{3i}$$

$$X^{\text{se}}_{bh} = X^{\text{se}}_{b,h-1} + \Delta \cdot \left(\sum_{t \in \mathcal{T}_b} \eta^{+}_{bt} \cdot X^{\text{pts}}_{bth} - X^{\text{dfs}}_{bh} / \eta^{-}_{b} - w^{\text{d}}_{b} \cdot X^{\text{se}}_{bh} \right) \quad \forall b \in \mathcal{B}^{\text{th}}, h \in \mathcal{H} \tag{3j}$$

$$X^{\text{se}}_{bh} \geq \underline{w}^{\text{mcp}}_{b} \cdot X^{\text{bkWh}}_{b} \quad \forall b \in \mathcal{B}, h \in \mathcal{H} \tag{3k}$$

Constraints (3d) and (3e) restrict the electrical power that charges storage and is exported to the grid (in the former case), or that charges storage only (in the latter case, when grid export is unavailable) from each technology in each time step relative to the amount of electricity produced. Constraint (3f) provides an analogous restriction to that of constraint (3e) for thermal production, and constraint (3g) provides the same restriction for the thermal production of CHP systems. Constraints (3h), (3i), and (3j) balance state-of-charge for each storage system and time period for three specific cases, respectively: (i) available grid-purchased electricity, (ii) lack of grid-purchased electricity, and (iii) thermal storage, in which we account for decay. Constraint (3k) ensures that minimum state of charge requirements are not violated.

Charging Rates

$$X^{\text{bkW}}_{b} \geq \sum_{t \in \mathcal{T}_b} X^{\text{pts}}_{bth} + X^{\text{gts}}_{h} + X^{\text{dfs}}_{bh} \quad \forall b \in \mathcal{B}^{\text{e}}, h \in \mathcal{H}^{\text{g}} \tag{3l}$$

$$X^{\text{bkW}}_{b} \geq \sum_{t \in \mathcal{T}_b} X^{\text{pts}}_{bth} + X^{\text{dfs}}_{bh} \quad \forall b \in \mathcal{B}^{\text{e}}, h \in \mathcal{H} \setminus \mathcal{H}^{\text{g}} \tag{3m}$$

$$X^{\text{bkW}}_{b} \geq \sum_{t \in \mathcal{T}_b} X^{\text{pts}}_{bth} + X^{\text{dfs}}_{bh} \quad \forall b \in \mathcal{B}^{\text{th}}, h \in \mathcal{H} \tag{3n}$$

$$X^{\text{se}}_{bh} \leq X^{\text{bkWh}}_{b} \quad \forall b \in \mathcal{B}, h \in \mathcal{H} \tag{3o}$$

Constraints (3l) and (3m) require that power available must meet or exceed that put into or discharged from storage; the latter constraint considers the case in which the grid is not available. Constraint (3n) reflects the power requirements for the thermal system. Constraint (3o) requires a storage system's energy level to be at or below the corresponding rating.

Cold and hot thermal loads

$$\sum_{t \in \mathcal{T}^{cl}} f^{\text{p}}_{th} \cdot X^{\text{tp}}_{th} + \sum_{b \in \mathcal{B}^{\text{c}}} X^{\text{dfs}}_{bh} = \delta^{\text{c}}_{h} \cdot \eta^{\text{ec}} + \sum_{b \in \mathcal{B}^{\text{c}}, t \in \mathcal{T}^{\text{cl}}} X^{\text{pts}}_{bth} \quad \forall h \in \mathcal{H} \tag{4a}$$

$$\sum_{t \in \mathcal{T}^{\text{CHP}}} X^{\text{tp}}_{th} + \sum_{t \in \mathcal{T}^{\text{ht}} \setminus \mathcal{T}^{\text{CHP}}} f^{\text{p}}_{th} \cdot X^{\text{tp}}_{th} + \sum_{b \in \mathcal{B}^{\text{h}}} X^{\text{dfs}}_{bh} = \delta^{\text{h}}_{h} \cdot \eta^{\text{b}} + \sum_{t \in \mathcal{T}^{\text{CHP}}} X^{\text{ptw}}_{th} + \sum_{b \in \mathcal{B}^{\text{h}}, t \in \mathcal{T}^{\text{ht}}} X^{\text{pts}}_{bth} + \sum_{t \in \mathcal{T}^{\text{ac}}} X^{\text{tp}}_{th} / \eta^{\text{ac}} \quad \forall h \in \mathcal{H} \tag{4b}$$

Constraints (4a) and (4b) balance cold and hot thermal loads, respectively, by equating the power production and the power from storage with the sum of the demand, the power to storage, and, in the case of cold loads, from the absorption chillers as well. Here, for legacy reasons, we have scaled the power by the efficiency of the respective technology; based on our variable definitions, we could have equivalently adjusted these by a coefficient of performance.

1.4.4 Production Constraints

$$X^{\mathrm{rp}}_{th} \leq \bar{b}^{\sigma}_{t} \cdot Z^{\mathrm{to}}_{th} \quad \forall t \in \mathcal{T}, h \in \mathcal{H} \tag{5a}$$

$$\underline{f}^{\mathrm{td}}_{t} \cdot X^{\sigma}_{t} - X^{\mathrm{rp}}_{th} \leq \bar{b}^{\sigma}_{t} \cdot (1 - Z^{\mathrm{to}}_{th}) \quad \forall t \in \mathcal{T}, h \in \mathcal{H} \tag{5b}$$

$$X^{\mathrm{tp}}_{th} \leq X^{\sigma}_{t} \quad \forall t \in \mathcal{T} \setminus \mathcal{T}^{\mathrm{e}}, h \in \mathcal{H} \tag{5c}$$

Constraint set (5) ensures that the rated production lies between a minimum turn-down threshold and a maximum system size; constraints (5a)-(5b) are copied from Ogunmodede et al. (2021), while constraint (5c) is available in Hirwa et al. (2022). Constraint (5a) restricts system power output to its rated capacity when the technology is operating, and to 0 otherwise. Constraint (5b) ensures a minimum power output while a technology is operating; otherwise, the constraint is dominated by simple bounds on production. Constraint (5c) ensures that the thermal production of non-CHP heating and cooling technologies does not exceed system size.

1.4.5 Production Incentives

$$X^{\mathrm{pi}}_{t} \leq \min\left\{ \bar{\imath}_{t} \cdot Z^{\mathrm{pi}}_{t} \,, \sum_{h \in \mathcal{H}} \Delta \cdot i^{\mathrm{r}}_{t} \cdot f^{\mathrm{pi}}_{t} \cdot f^{\mathrm{p}}_{th} \cdot f^{\mathrm{li}}_{t} \cdot X^{\mathrm{rp}}_{th} \right\} \quad \forall t \in \mathcal{T} \tag{6a}$$

$$X^{\sigma}_{t} \leq \bar{\imath}^{\sigma}_{t} + M \cdot (1 - Z^{\mathrm{pi}}_{t}) \quad \forall t \in \mathcal{T} \tag{6b}$$

Constraint (6a) calculates total production incentives, if available, for each technology. Constraint (6b) sets an upper bound on the size of system that qualifies for production incentives, if production incentives are available.

1.4.6 Power Rating

$$X^{\sigma}_{t} \leq \bar{b}^{\sigma}_{t} \cdot \sum_{s \in \mathcal{S}_{tk}} Z^{\sigma\mathrm{s}}_{tks} \quad \forall c \in \mathcal{C}, t \in \mathcal{T}_{c}, k \in \mathcal{K}_{t} \tag{7a}$$

$$\sum_{t \in \mathcal{T}_{c}, s \in \mathcal{S}_{tk}} Z^{\sigma\mathrm{s}}_{tks} \leq 1 \quad \forall c \in \mathcal{C}, k \in \mathcal{K} \tag{7b}$$

$$\sum_{t \in \mathcal{T}_{c}} X^{\sigma}_{t} \geq \underline{b}^{\sigma}_{c} \quad \forall c \in \mathcal{C} \tag{7c}$$

$$X^{\mathrm{rp}}_{th} = X^{\sigma}_{t} \quad \forall t \in \mathcal{T}^{\mathrm{td}}, h \in \mathcal{H} \tag{7d}$$

$$X^{\mathrm{rp}}_{th} \leq f^{\mathrm{ed}}_{th} \cdot X^{\sigma}_{t} \quad \forall t \in \mathcal{T} \setminus \mathcal{T}^{\mathrm{td}}, h \in \mathcal{H} \tag{7e}$$

$$\underline{b}^{\sigma\mathrm{s}}_{tks} \cdot Z^{\sigma\mathrm{s}}_{tks} \leq X^{\sigma\mathrm{s}}_{tks} \leq \bar{b}^{\sigma\mathrm{s}}_{tks} \cdot Z^{\sigma\mathrm{s}}_{tks} \quad \forall t \in \mathcal{T}, k \in \mathcal{K}_{t}, s \in \mathcal{S}_{tk} \tag{7f}$$

$$\sum_{s \in \mathcal{S}_{tk}} X^{\sigma\mathrm{s}}_{tks} = X^{\sigma}_{t} \quad \forall t \in \mathcal{T}, k \in \mathcal{K}_{t} \tag{7g}$$

Constraint (7a) permits nonzero power ratings only for the selected technology and corresponding subdivision in each class. Constraint (7b) allows at most one technology to be chosen for each subdivision in each class. Constraint (7c) limits the power rating to the minimum allowed for a technology class. Constraint (7d) prevents renewable technologies from turning down; rather, they must provide output at their nameplate capacity. Constraint (7e) limits rated production from all non-renewable technologies to be less than or equal to the product of the power rating and the derate factor for each time period. Constraint (7f) imposes both lower and upper limits on power rating of a technology, allocated to a subdivision in a segment, and constraint (7g) sums the segment sizes to the total for a given technology and subdivision.

1.4.7 Load Balancing and Grid Sales

$$\sum_{t\in\mathcal{T}^{\mathrm{e}}}(f^{\mathrm{p}}_{th}\cdot f^{\mathrm{l}}_{t}\cdot X^{\mathrm{rp}}_{th}) + \sum_{b\in\mathcal{B}^{\mathrm{e}}} X^{\mathrm{dfs}}_{bh} + \sum_{u\in\mathcal{U}^{\mathrm{p}}} X^{\mathrm{g}}_{uh} = \sum_{t\in\mathcal{T}^{\mathrm{e}}}\left(\sum_{b\in\mathcal{B}^{\mathrm{e}}} X^{\mathrm{pts}}_{bth} + \sum_{u\in\mathcal{U}^{\mathrm{s}}_{t}} X^{\mathrm{ptg}}_{tuh} + X^{\mathrm{ptc}}_{th}\right)$$
$$+ \sum_{u\in\mathcal{U}^{\mathrm{sb}}} X^{\mathrm{stg}}_{uh} + X^{\mathrm{gts}}_{h} + \sum_{t\in\mathcal{T}^{ec}} X^{\mathrm{tp}}_{th}/\eta^{\mathrm{ec}} + \sum_{t\in\mathcal{T}^{\mathrm{ac}}} X^{\mathrm{tp}}_{th}/\eta^{\text{ac-e}} + \delta^{\mathrm{d}}_{h}\cdot X^{\mathrm{e}}_{h} \quad \forall h\in\mathcal{H}^{g} \tag{8a}$$

$$\sum_{t\in\mathcal{T}^{\mathrm{e}}}(f^{\mathrm{p}}_{th}\cdot f^{\mathrm{l}}_{t}\cdot X^{\mathrm{rp}}_{th}) + \sum_{b\in\mathcal{B}^{\mathrm{e}}} X^{\mathrm{dfs}}_{bh} = \sum_{t\in\mathcal{T}^{\mathrm{e}}}\left(\sum_{b\in\mathcal{B}^{\mathrm{e}}} X^{\mathrm{pts}}_{bth} + X^{\mathrm{ptc}}_{th}\right)$$
$$+ \sum_{t\in\mathcal{T}^{\mathrm{ec}}} X^{\mathrm{tp}}_{th}/\eta^{\mathrm{ec}} + \sum_{t\in\mathcal{T}^{\mathrm{ac}}} X^{\mathrm{tp}}_{th}/\eta^{\text{ac-e}} + \delta^{\mathrm{d}}_{h}\cdot X^{\mathrm{e}}_{h} \quad \forall h\in\mathcal{H}\setminus\mathcal{H}^{g} \tag{8b}$$

$$\sum_{u\in\mathcal{U}^{\mathrm{p}}} X^{\mathrm{g}}_{uh} \geq X^{\mathrm{gts}}_{h} \quad \forall h\in\mathcal{H}^{\mathrm{g}} \tag{8c}$$

$$\sum_{b\in\mathcal{B}^{\mathrm{e}}} X^{\mathrm{dfs}}_{bh} \geq \sum_{u\in\mathcal{U}^{\mathrm{sb}}} X^{\mathrm{stg}}_{uh} \quad \forall h\in\mathcal{H}^{\mathrm{g}} \tag{8d}$$

$$\Delta\cdot\sum_{h\in\mathcal{H}^{\mathrm{g}}}\left(X^{\mathrm{stg}}_{uh} + \sum_{t\in\mathcal{T}_{u}} X^{\mathrm{ptg}}_{tuh}\right) \leq \bar{\delta}^{\mathrm{gs}}_{u} \quad \forall u\in\mathcal{U}^{\mathrm{sb}}\cap\mathcal{U}^{\mathrm{nm}} \tag{8e}$$

$$\Delta\cdot\sum_{h\in\mathcal{H}^{\mathrm{g}},t\in\mathcal{T}_{u}} X^{\mathrm{ptg}}_{tuh} \leq \bar{\delta}^{\mathrm{gs}}_{u} \quad \forall u\in\mathcal{U}^{\mathrm{nm}}\setminus\mathcal{U}^{\mathrm{sb}} \tag{8f}$$

Constraint (8a) balances load by requiring that the sum of power (i) produced, (ii) discharged from storage, and (iii) purchased from the grid is equal to the sum of (i) the power charged to storage, (ii) the power sold to the grid from in-house production or storage, (iii) the power charged to storage directly from the grid, (iv) any additional power consumed by the electric and absorption chillers (where these are additional terms relative to the original model ($\mathcal{R}$)), and (v) the electrical load on site. Constraint (8b) provides an analogous load-balancing requirement for hours in which the site is disconnected from the grid due to an outage (and contains the same additional term relative to the original model ($\mathcal{R}$)). Constraint (8c) restricts charging of storage from grid production to the grid power purchased for each hour. Similarly, constraint (8d) restricts the sales from the electrical storage system to its rate of discharge in each time period. Constraints (8e) and (8f) restrict the annual energy sold to the grid at net-metering rates; only one of these is implemented in each case according to user-specified options. While a collection of pre-specified technologies may contribute to net-metering rates in both cases, constraint (8e) allows storage to contribute to net-metering while constraint (8f) does not.

1.4.8 Rate Tariff Constraints

Net Metering

$$\sum_{v\in\mathcal{V}} Z_v^{\text{nmil}} = 1 \tag{9a}$$

$$\sum_{t\in\mathcal{T}_v} f_t^{\text{d}} \cdot X_t^{\sigma} \le i_v^{\text{n}} \cdot Z_v^{\text{nmil}} \quad \forall v \in \mathcal{V} \tag{9b}$$

$$\Delta \cdot \sum_{h\in\mathcal{H}^{\text{g}}} \left(\sum_{u\in\mathcal{U}^{\text{nm}}, t\in\mathcal{T}_u} X_{tuh}^{\text{ptg}} + \sum_{u\in\mathcal{U}^{\text{nm}}\cap\mathcal{U}^{\text{sb}}} X_{uh}^{\text{stg}} \right) \le \Delta \cdot \sum_{u\in\mathcal{U}^{\text{p}}, h\in\mathcal{H}^{\text{g}}} X_{uh}^{\text{g}} \tag{9c}$$

Constraint (9a) limits the net metering to a single regime at a time. Constraint (9b) restricts the sum of the power rating of all technologies to be less than or equal to the net metering regime. Constraint (9c) ensures that energy sales at net-metering rates do not exceed the energy purchased from the grid.

Monthly Total Demand Charges

$$\Delta \cdot \sum_{h\in\mathcal{H}_m} X_{uh}^{\text{g}} \le \bar{\delta}_u^{\text{tu}} \cdot Z_{mu}^{\text{ut}} \quad \forall m \in \mathcal{M}, u \in \mathcal{U}^{\text{p}} \tag{10a}$$

$$Z_{mu}^{\text{ut}} \le Z_{m,u-1}^{\text{ut}} \quad \forall u \in \mathcal{U}^{\text{p}} : u \ge 2, m \in \mathcal{M} \tag{10b}$$

$$\bar{\delta}_{u-1}^{\text{tu}} \cdot Z_{mu}^{\text{ut}} \le \Delta \cdot \sum_{h\in\mathcal{H}_m} X_{u-1,h}^{\text{g}} \quad \forall u \in \mathcal{U}^{\text{p}} : u \ge 2, m \in \mathcal{M} \tag{10c}$$

Constraint (10a) limits the quantity of electrical energy purchased from the grid in a given month from a specified pricing tier to the maximum available. Constraint (10b) forces pricing tiers to be charged in a specific order, and constraint (10c) forces one pricing tier's purchases to be at capacity if any charges are applied to the next tier.

Peak Power Demand Charges: Months

$$X_{mn}^{\text{dn}} \le \bar{\delta}_n^{\text{mt}} \cdot Z_{mn}^{\text{dmt}} \quad \forall n \in \mathcal{N}, m \in \mathcal{M} \tag{11a}$$

$$Z_{mn}^{\text{dmt}} \le Z_{m,n-1}^{\text{dmt}} \quad \forall n \in \mathcal{N} : n \ge 2, m \in \mathcal{M} \tag{11b}$$

$$\bar{\delta}_{n-1}^{\text{mt}} \cdot Z_{mn}^{\text{dmt}} \le X_{m,n-1}^{\text{dn}} \quad \forall n \in \mathcal{N} : n \ge 2, m \in \mathcal{M} \tag{11c}$$

$$\sum_{n\in\mathcal{N}} X_{mn}^{\text{dn}} \ge \sum_{u\in\mathcal{U}^{\text{p}}} X_{uh}^{\text{g}} \quad \forall m \in \mathcal{M}, h \in \mathcal{H}_m \tag{11d}$$

Constraint (11a) limits the energy demand allocated to each tier to no more than the maximum demand allowed. Constraint (11b) forces monthly demand tiers to become active in a prespecified order. Constraint (11c) forces demand to be met in one tier before the next demand tier. Constraint (11d) defines the peak demand to be greater than or equal to all of the demands across the time horizon, where an equality is actually induced by the sense of the objective function. A user-defined option precludes CHP technology production from reducing peak demand; if selected, constraint (11d) becomes:

$$\sum_{n\in\mathcal{N}} X_{mn}^{\text{dn}} \ge \sum_{u\in\mathcal{U}^{\text{p}}} X_{uh}^{\text{g}} + \sum_{t\in\mathcal{T}^{\text{CHP}}} \left(f_{th}^{\text{p}} \cdot f_t^{\text{l}} \cdot X_{th}^{\text{rp}} - \sum_{b\in\mathcal{B}^{\text{h}}} X_{bth}^{\text{pts}} - \sum_{u\in\mathcal{U}_t^{s}} X_{tuh}^{\text{ptg}} \right)$$

$$\forall m \in \mathcal{M}, h \in \mathcal{H}_m.$$

Peak Power Demand Charges: Time-of-Use Demand and Ratchet Charges

$$X^{\mathrm{de}}_{de} \leq \bar{\delta}^{\mathrm{t}}_{e} \cdot Z^{\mathrm{dt}}_{de} \quad \forall e \in \mathcal{E}, d \in \mathcal{D} \tag{12a}$$

$$Z^{\mathrm{dt}}_{de} \leq Z^{\mathrm{dt}}_{d,e-1} \quad \forall e \in \mathcal{E} : e \geq 2, d \in \mathcal{D} \tag{12b}$$

$$\bar{\delta}^{\mathrm{t}}_{e-1} \cdot Z^{\mathrm{dt}}_{de} \leq X^{\mathrm{de}}_{d,e-1} \quad \forall e \in \mathcal{E} : e \geq 2, d \in \mathcal{D} \tag{12c}$$

$$\sum_{e \in \mathcal{E}} X^{\mathrm{de}}_{de} \geq \max\{\sum_{u \in \mathcal{U}^{\mathrm{p}}} X^{\mathrm{g}}_{uh}, \delta^{\mathrm{lp}} \cdot X^{\mathrm{plb}}\} \quad \forall d \in \mathcal{D}, h \in \mathcal{H}_d \tag{12d}$$

$$X^{\mathrm{plb}} \geq \sum_{n \in \mathcal{N}} X^{\mathrm{dn}}_{mn} \quad \forall m \in \mathcal{M}^{\mathrm{lb}} \tag{12e}$$

Constraints (12a)-(12d) correspond to constraints (11a)-(11d), respectively, but pertain to a type of charge not related to monthly use, but rather to time of use within a month. These *ratchet charges* are implemented using constraints (12d). The charge applied for each time-of-use period is a linearizable function of the greater of the peak electrical demand during that period (as given by the first term on the right-hand side of (12d)) and a fraction of the peak demand that occurs over a collection of months (known as *look-back months*) during the year (as given by the second term on the right-hand side of (12d)). Constraint (12d) ensures the peak demand over the set of look-back months is no lower than the peak demand for each look-back month. In this way, charges are based not only on use in a given month, but also on a fraction of use over the last several months, and becomes relevant when this latter use is high relative to current use. If CHP technologies are not allowed to reduce peak demand, constraint (12d) becomes:

$$\sum_{e \in \mathcal{E}} X^{\mathrm{de}}_{de} \geq \sum_{u \in \mathcal{U}^{\mathrm{p}}} X^{\mathrm{g}}_{uh} + \sum_{t \in \mathcal{T}^{\mathrm{CHP}}} \left(f^{\mathrm{p}}_{th} \cdot f^{\mathrm{l}}_{t} \cdot X^{\mathrm{rp}}_{th} - \sum_{b \in \mathcal{B}^{\mathrm{h}}} X^{\mathrm{pts}}_{bth} - \sum_{u \in \mathcal{U}^{\mathrm{s}}_{t}} X^{\mathrm{ptg}}_{tuh} \right)$$
$$\forall d \in \mathcal{D}, h \in \mathcal{H}_d.$$

1.4.9 Minimum Utility Charge

$$X^{\mathrm{mc}} \geq c^{\mathrm{amc}} - \Bigg(\underbrace{\Delta \cdot \sum_{u \in \mathcal{U}^{\mathrm{p}}, h \in \mathcal{H}^{\mathrm{g}}} c^{\mathrm{g}}_{uh} \cdot X^{\mathrm{g}}_{uh}}_{\text{Grid Energy Charges}} + \underbrace{\sum_{d \in \mathcal{D}, e \in \mathcal{E}} c^{\mathrm{r}}_{de} \cdot X^{\mathrm{de}}_{de}}_{\text{Time-of-Use Demand Charges}} + \underbrace{\sum_{m \in \mathcal{M}, n \in \mathcal{N}} c^{\mathrm{rm}}_{mn} \cdot X^{\mathrm{dn}}_{mn}}_{\text{Monthly Demand Charges}} - \underbrace{\Delta \cdot \left(\sum_{h \in \mathcal{H}^{\mathrm{g}}} \left(\sum_{u \in \mathcal{U}^{\mathrm{sb}}} c^{\mathrm{e}}_{uh} \cdot X^{\mathrm{stg}}_{uh} + \sum_{t \in \mathcal{T}, u \in \mathcal{U}^{\mathrm{s}}_{t}} c^{\mathrm{e}}_{uh} \cdot X^{\mathrm{ptg}}_{tuh} \right)\right)}_{\text{Energy Export Payment}} \Bigg) \tag{13}$$

Constraint (13) enforces a minimum payment to the utility provider, which is a fixed constant less charges incurred from grid energy, time-of-use demand and monthly demand payments, plus sales from exports to the grid.

1.4.10 Operating Reserves

$$X^{\ell}_{th} = f^{\rm p}_{th} \cdot f^{\rm l}_{t} \cdot X^{\rm rp}_{th} - \Big(\sum_{b\in\mathcal{B}^{\rm e}} X^{\rm pts}_{bth} + X^{\rm ptc}_{th}\Big) \forall t \in \mathcal{T}^{s}, h \in \mathcal{H}\setminus\mathcal{H}^{\rm g} \tag{14a}$$

$$X^{r}_{h} = \theta^{\ell}_{h} \cdot \delta^{\rm d}_{h} \cdot X^{\rm e}_{h} + \theta^{\rm pv}_{h} \cdot X^{\ell}_{``PV",h} \quad \forall h \in \mathcal{H}\setminus\mathcal{H}^{\rm g} \tag{14b}$$

$$X^{\text{ar-b}}_{h} \leq \min\left\{ \frac{X^{\rm se}_{b,h-1} - \underline{w}^{\rm mcp}_{b} \cdot X^{\rm bkWh}_{b}}{\Delta} - \frac{X^{\rm dfs}_{h}}{\eta^{-}_{b}}, X^{\rm bkW}_{b} - \frac{X^{\rm dfs}_{h}}{\eta^{-}_{b}} \right\} \forall h \in \mathcal{H}\setminus\mathcal{H}^{\rm g} \tag{14c}$$

$$X^{\rm ar}_{th} \leq X^{\sigma}_{t} - (1-\theta^{\rm pv}_{h}) \cdot X^{\ell}_{th} \quad \forall t \in \mathcal{T}^{s} \ni t = \text{“PV”}, h \in \mathcal{H}\setminus\mathcal{H}^{\rm g} \tag{14d}$$

$$X^{\rm ar}_{th} \leq X^{\sigma}_{t} - X^{\ell}_{th} \quad \forall t \in \mathcal{T}^{s} \ni t = \text{generator}, h \in \mathcal{H}\setminus\mathcal{H}^{\rm g} \tag{14e}$$

$$X^{\rm ar}_{th} \leq \bar{b}^{\sigma}_{t} \cdot Z^{\rm to}_{th} \quad \forall t \in \mathcal{T}^{s}, h \in \mathcal{H}\setminus\mathcal{H}^{\rm g} \tag{14f}$$

$$X^{\rm r}_{h} \leq X^{\text{ar-b}}_{h} + X^{\rm ar}_{th} \quad \forall h \in \mathcal{H}\setminus\mathcal{H}^{\rm g} \tag{14g}$$

$$\sum_{h\in\mathcal{H}} \delta^{\rm d}_{h} \cdot X^{\rm e}_{h} \geq \underline{\delta}^{\rm an} \cdot \sum_{h\in\mathcal{H}} \delta^{\rm d}_{h} \tag{14h}$$

Constraints (14a) define the load served as the sum of (i) production less (ii) the quantity sold and less (iii) storage (both produced and coming from the grid). Constraints (14b) require the total operating reserves in any time step to be at least the sum of the load and PV operating reserve requirements. Constraints (14c) ensure that the operating reserves provided by the battery in any time step be no more than both the excess available energy and the power capacity. Constraints (14d) and (14e) guarantee that the operating reserves provided by PV and the generator, respectively, must be less than or equal to the excess available capacity for each technology in time step, while constraints (14f) ensure that these operating reserves can only be provided if the corresponding devices are operational in that time step. Total operating reserves, as given by the sum of the generators and PV devices, must be greater than those required for each time step by (14g) while the total annual load served must be at least the minimum specified (constraints (14h)).

1.4.11 Emissions and Renewable Production Targets

$$\underline{b}^{\rm e}_{p} \leq f^{\rm fe}_{p} \cdot \sum_{t\in\mathcal{T}^{\rm f}, h\in\mathcal{H}} \Delta \cdot e^{\rm f}_{pt} \cdot X^{\rm f}_{th} + f^{\rm ge}_{p} \cdot \sum_{h\in\mathcal{H}, u\in\mathcal{U}} \Delta \cdot e^{\rm g}_{ph} \cdot X^{\rm g}_{uh} \leq \bar{b}^{\rm e}_{p}, \ \forall p \in \mathcal{P}^{\rm r} \tag{15a}$$

$$\sum_{t\in\mathcal{T}^{\rm e}, h\in\mathcal{H}} \left(f^{\rm p}_{th} \cdot f^{\rm l}_{t} \cdot f^{\rm re}_{t} \cdot X^{\rm rp}_{th} - \sum_{b\in\mathcal{B}^{\rm e}} \left((1-\eta^{+}_{bt}) \cdot X^{\rm pts}_{bth} \right) - X^{\rm ptc}_{th} \right) \geq \underline{b}^{\rm re} \cdot \sum_{h\in\mathcal{H}} \left(\sum_{t\in\mathcal{T}^{\rm ec}} X^{\rm tp}_{th}/\eta^{\rm ec} + \sum_{t\in\mathcal{T}^{\rm ac}} X^{\rm tp}_{th}/\eta^{\text{ac-e}} + \delta^{\rm d}_{h} \right) \tag{15b}$$

$$\sum_{t\in\mathcal{T}^{\rm e}, h\in\mathcal{H}} \left(f^{\rm p}_{th} \cdot f^{\rm l}_{t} \cdot f^{\rm re}_{t} \cdot X^{\rm rp}_{th} - \sum_{b\in\mathcal{B}^{\rm e}} \left((1-\eta^{+}_{bt}) \cdot X^{\rm pts}_{bth} \right) - X^{\rm ptc}_{th} \right) \leq \bar{b}^{\rm re} \cdot \sum_{h\in\mathcal{H}} \left(\sum_{t\in\mathcal{T}^{\rm ec}} X^{\rm tp}_{th}/\eta^{\rm ec} + \sum_{t\in\mathcal{T}^{\rm ac}} X^{\rm tp}_{th}/\eta^{\text{ac-e}} + \delta^{\rm d}_{h} \right) \tag{15c}$$

$$\sum_{t\in\mathcal{T}^{\mathrm{ht}},h\in\mathcal{H}}\left(f^{\mathrm{p}}_{th}\cdot f^{\mathrm{l}}_{t}\cdot f^{\mathrm{rh}}_{t}\cdot X^{\mathrm{tp}}_{th}-\sum_{b\in\mathcal{B}^{\mathrm{h}}}\left((1-\eta^{+}_{bt})\cdot X^{\mathrm{pts}}_{bth}\right)-X^{\mathrm{ptw}}_{th}\right)\geq$$

$$\underline{b}^{\mathrm{rh}}\cdot\sum_{h\in\mathcal{H}}\left(\sum_{t\in\mathcal{T}^{\mathrm{ac}}}X^{\mathrm{tp}}_{th}/\eta^{\mathrm{ac}}+\delta^{\mathrm{h}}_{h}\right) \tag{15d}$$

$$\sum_{t\in\mathcal{T}^{\mathrm{ht}},h\in\mathcal{H}}\left(f^{\mathrm{p}}_{th}\cdot f^{\mathrm{l}}_{t}\cdot f^{\mathrm{rh}}_{t}\cdot X^{\mathrm{tp}}_{th}-\sum_{b\in\mathcal{B}^{\mathrm{h}}}\left((1-\eta^{+}_{bt})\cdot X^{\mathrm{pts}}_{bth}\right)-X^{\mathrm{ptw}}_{th}\right)\leq$$

$$\bar{b}^{\mathrm{rh}}\cdot\sum_{h\in\mathcal{H}}\left(\sum_{t\in\mathcal{T}^{\mathrm{ac}}}X^{\mathrm{tp}}_{th}/\eta^{\mathrm{ac}}+\delta^{\mathrm{h}}_{h}\right) \tag{15e}$$

Constraint (15a) places bounds on the total lifecycle emissions attributed to fuel consumption on site and electricity purchases from the grid. These limits are derived from user-specified emissions reduction targets. Constraints (15b) and (15c) enforce an upper and lower bound on the total electricity produced by onsite renewable technologies, respectively; these are presented as fractions of the total electricity consumed on site. Constraints (15d) nd (15e) establish analogous bounds to those of constraints (15b) and (15c), respectively, on the usable heat produced by renewables.

1.4.12 Non-negativity

$$X^{\mathrm{plb}}, X^{\mathrm{mc}}\geq 0 \tag{16a}$$
$$X^{\sigma}_{t}, X^{\mathrm{pi}}_{t}\geq 0\quad\forall t\in\mathcal{T} \tag{16b}$$
$$X^{\mathrm{ptg}}_{tuh}\geq 0\quad\forall u\in\mathcal{U}, t\in\mathcal{T}_{u}, h\in\mathcal{H} \tag{16c}$$
$$X^{\mathrm{stg}}_{uh}, X^{\mathrm{g}}_{uh}\geq 0\quad\forall u\in\mathcal{U}, h\in\mathcal{H} \tag{16d}$$
$$X^{\mathrm{de}}_{de}\geq 0\quad\forall d\in\mathcal{D}, e\in\mathcal{E} \tag{16e}$$
$$X^{\mathrm{dn}}_{mn}\geq 0\quad\forall m\in\mathcal{M}, n\in\mathcal{N} \tag{16f}$$
$$X^{\mathrm{gts}}_{h}\geq 0\quad h\in\mathcal{H} \tag{16g}$$
$$X^{\mathrm{bkW}}_{b}, X^{\mathrm{bkWh}}_{b}\geq 0\quad b\in\mathcal{B} \tag{16h}$$
$$X^{\sigma\mathrm{s}}_{tks}\geq 0\quad\forall t\in\mathcal{T},\ k\in\mathcal{K},\ s\in\mathcal{S}_{tk} \tag{16i}$$
$$X^{\mathrm{pts}}_{bth}\geq 0\quad\forall b\in\mathcal{B},\ t\in\mathcal{T},\ h\in\mathcal{H} \tag{16j}$$
$$X^{\mathrm{se}}_{bh}, X^{\mathrm{dfs}}_{bh}\geq 0\quad\forall b\in\mathcal{B},\ h\in\mathcal{H} \tag{16k}$$
$$X^{\mathrm{rp}}_{th}, X^{\mathrm{f}}_{th}, X^{\mathrm{fb}}_{th}, X^{\mathrm{tpb}}_{th}, X^{\mathrm{tp}}_{th}, X^{\mathrm{ptw}}_{th}, X^{\mathrm{ptc}}_{th}\geq 0\quad\forall t\in\mathcal{T},\ h\in\mathcal{H} \tag{16l}$$

1.4.13 Integrality

$$Z^{\mathrm{nmil}}_{v}\in\{0,1\}\quad\forall v\in\mathcal{V} \tag{17a}$$
$$Z^{\sigma\mathrm{s}}_{tks}\in\{0,1\}\quad\forall t\in\mathcal{T},\ k\in\mathcal{K},\ s\in\mathcal{S}_{tk} \tag{17b}$$
$$Z^{\mathrm{pi}}_{t}\in\{0,1\}\quad\forall t\in\mathcal{T} \tag{17c}$$
$$Z^{\mathrm{to}}_{th}\in\{0,1\}\quad\forall t\in\mathcal{T}, h\in\mathcal{H} \tag{17d}$$
$$Z^{\mathrm{dt}}_{de}\in\{0,1\}\quad\forall d\in\mathcal{D}, e\in\mathcal{E} \tag{17e}$$
$$Z^{\mathrm{dmt}}_{mn}\in\{0,1\}\quad\forall m\in\mathcal{M}, n\in\mathcal{N} \tag{17f}$$
$$Z^{\mathrm{ut}}_{mu}\in\{0,1\}\quad\forall m\in\mathcal{M}, u\in\mathcal{U} \tag{17g}$$

Finally, constraints (16) ensure all of the variables in our formulation assume non-negative values. In addition to non-negativity restrictions, constraints (17) establish the integrality of the appropriate variables.

References

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